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THE UNIVERSITY OF ALBERTA

PRORATIONING OF OIL IN ALBERTA AND SOME ECONOMIC IMPLICATIONS

by

© STELLA M. THOMPSON

A THESIS

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The undersigned certify that they have read, and recommend to the Faculty of Graduate Studies for acceptance, a thesis entitled PRORATIONING IN ALBERTA AND ITS ECONOMIC IMPLICATIONS submitted by Stella M. Thompson in partial fulfillment of the requirements for the degree of Master of Arts.

ABSTRACT

By May of 1969 a new system of prorationing will be fully implemented in Alberta. The purpose of this thesis is to analyse the conditions within the petroleum industry and the contentious issues of the previous prorationing system in Alberta that led to the formulation of a new proration plan. The effects of the new plan, and prorationing in general, on various economic variables are also analysed.

The basic conclusion of this thesis is that, given the conditions existing in Alberta, prorationing is necessary. Furthermore, while it is recognized that prorationing has some detrimental effects, it is concluded in the thesis that a system which combines the unitization of pools with prorationing to market demand between pools would maximize the benefits, while minimizing the disadvantages, both to the petroleum industry and to the economy of Alberta as a whole more than any other workable system.

ACKNOWLEDGEMENTS

I wish to thank Professor E.J. Hanson for both the guidance he has given me on the organization of my thesis and for the ready assistance he has given me on many occasions throughout my M.A. program.

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CHAPTER I

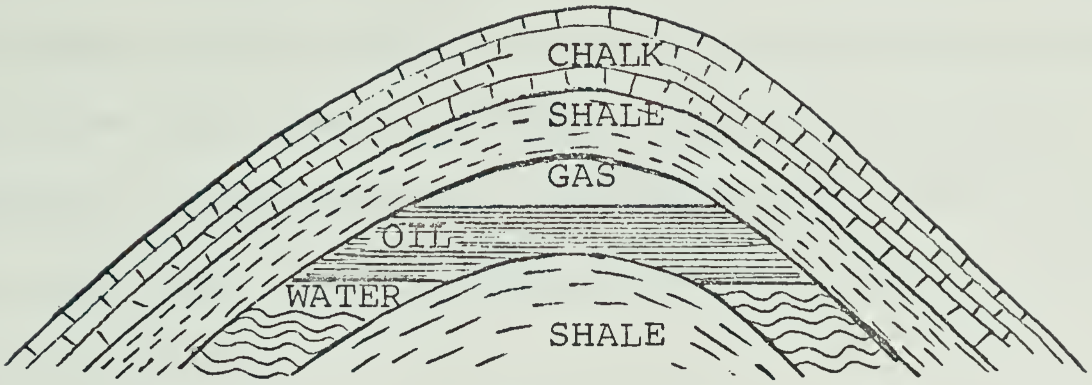
INTRODUCTION

PHYSICAL AND ECONOMIC CHARACTERISTICS OF PETROLEUM AND THE PETROLEUM INDUSTRY

Prorationing is a system of regulation unique to the petroleum industry. Briefly put, it is the limiting of the production of either gas or oil so as to meet no more than market demand. Since much of what applies to the regulation of the production of oil also applies to that of gas, this paper will deal only with the prorationing of oil.

In order to understand fully why prorationing has evolved, how a control of this type operates, and what its effects are on some of the other areas of the petroleum industry, it is necessary to be familiar with some of the physical and economic characteristics peculiar to the oil industry that have given rise to regulation of this type.

Oil is found in reservoirs, or pools as they are sometimes called. A pool is formed when oil becomes trapped in porous rock or sand which is in turn surrounded by strata that are impervious to the oil. In Figure 1 three kinds of formations that are often found



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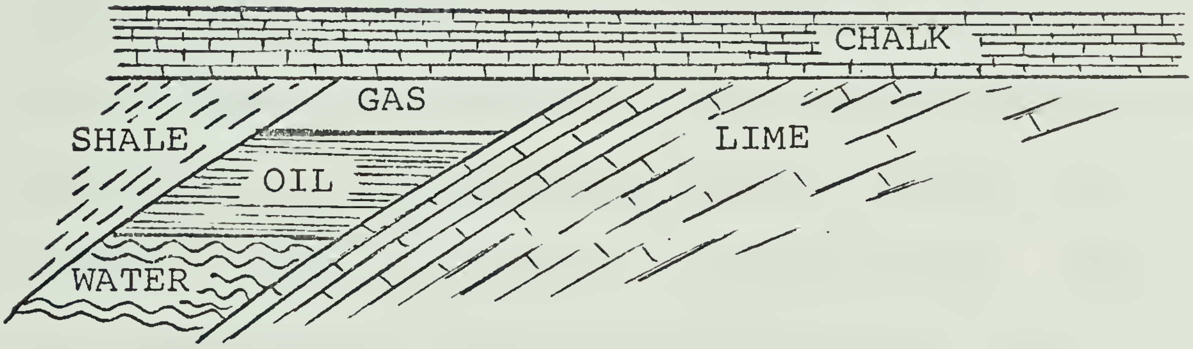
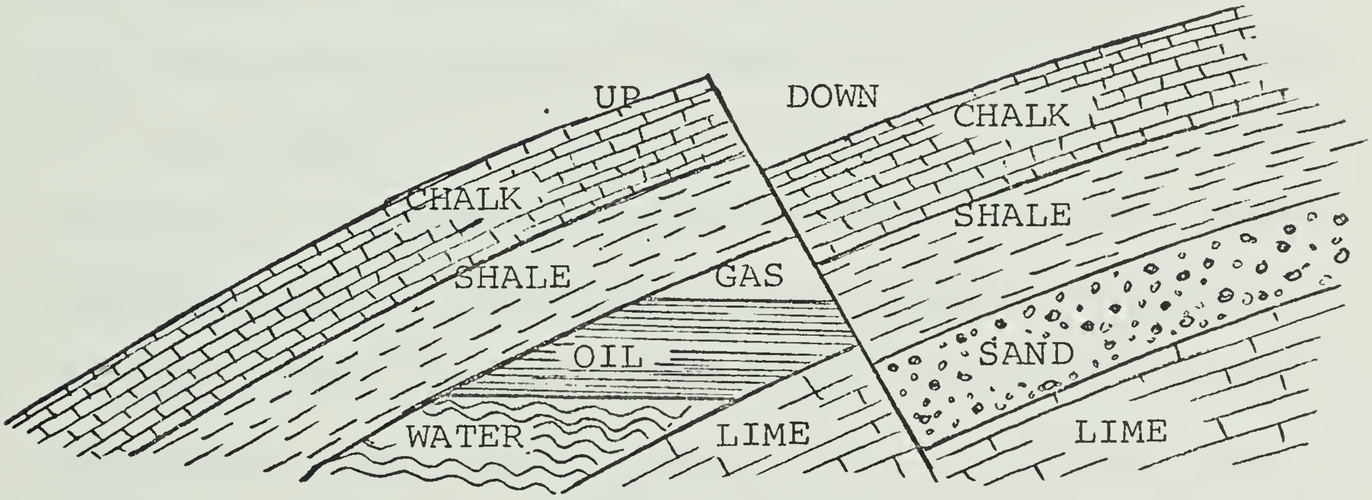


STRATOGRAPHIC TRAP



FAULT

Figure I: Common types of formations in which oil is found.

Source: Erich W. Zimmermann, Conservation in the Production of Petroleum, Petroleum Monograph Series, Vol. 2 (New Haven: Yale University Press, 1957), p.61.

to contain oil are illustrated. As can be seen from the diagrams, water and gas are usually found in conjunction with the oil, their different specific gravities causing a separation of the fluids into gas at the top, oil with some gas in solution in the middle, and water at the bottom.

Reservoirs can differ in many respects, such as their areal extent, their thickness, and the quality of their content. But for the purpose of understanding prorationing, the most important differences to note between pools are their so-called drives. Since crude oil possesses no energy of its own, the water below the oil and/or the gases dissolved in the oil must provide the necessary pressure to force the oil to the surface. If the pressure in a pool is allowed to fall because of wasteful or inefficient methods of production, pumping devices must be installed to pump the oil mechanically to the surface or, as in the case of secondary recovery projects, either water or gas must be injected back into the pool in order to build up the pressure once more. When either pumping or injecting becomes necessary the costs of production are greatly increased. Furthermore, premature dissipation of the natural drives can cause some of the oil in the reservoir to be locked in small pools and thus wasted since these pools are often too isolated and too hard to find to make drilling extra wells economical.

Another aspect of a reservoir that is important to the understanding of prorationing is that oil can flow from one part of the reservoir to another. As a result, one well is able to drain the oil from a large area of the pool. The area it is able to drain is of course not limited or restricted by the existing above-ground property rights of the well-owner. These unlimited underground rights are expressed in the "Rule of Capture", a rule which has, of necessity, evolved because of the "checkerboard" system of land ownership (to be discussed more fully later).

Another characteristic of the oil industry that has a bearing on prorationing is that the oil industry is very capital-intensive, requiring huge outlays even to begin production. In the oil industry these large sums of money are spent in the face of great uncertainty, for there are no foolproof methods of exploration and drilling that guarantee the finding of marketable oil. Thus, while in most industries accurate estimates can be made of how much extra capacity can be obtained by investing a given amount of money, in petroleum production[1] this is impossible for any given project, company, area, or even the whole industry. "If instead of $X

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[1] Here "production" refers to exploration, development and extraction.

of exploration expenditures, we spend $2X everything else remaining equal, we should hardly expect to get about twice as much. The additional reserves found might be negligible, or spectacularly large".[1]

Another peculiarity of the oil industry is the division of the industry into two opposing camps, the so-called "independents" and "majors". Originally, the name "independent" was given to any oil company which was not one of the companies resulting from the 1911 "dissolution" of the Standard Oil Company.[2] Now the term means any company which is not a "major".

Majors are generally those companies which are large in absolute size and are vertically integrated, i.e., they have operations at the producing, transporting, refining and marketing levels. Independents, on the other hand, generally operate at only one level, the majority of the independents being producers. The division between majors and independents, however, is not rigid, for some independents do operate at more than one level. Perhaps more realistic names for the two

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[1] M. A. Adelman, "The Supply and Price of Natural Gas," Journal of Industrial Economics, supplement (1962), p.7.

[2] Paul T. Homan, "General Structure and Problems of the Petroleum Industry," in Essays on Petroleum Conservation Regulation, ed. by Wallace F. Lovejoy and I. James Pikl, Jr. (Dallas, Texas: Southern Methodist University, 1960), p.5.

opposing camps would be the "fully integrated" companies versus the "partially or non-integrated" companies.

The need for prorationing arose partly because of the conflicting interests and capabilities of these two groups. For example, producing companies, of which there are many more independents than majors, far outnumber the purchasers of crude. The majority of purchasers (both in numbers and by size) are majors, most of whom are also producers. With most of the refining and transportation facilities being part of their integrated operations, in a situation where supply exceeds demand the majors will prefer to use their own oil first, leaving the independent producer with a very limited market for his oil. In a pool where ownership is divided amongst majors and independents and there are no regulations, the unequal availability of transportation and marketing facilities will lead to widely differing rates of production. When oil from a pool is produced at different rates in different parts of the pool, uneven pressure changes take place causing not only drainage of the oil across property lines but also wastage of the oil due to "channelling".[1]

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[1] In a pool, water is able to move through the sand towards the well (where the pressure is lower) more quickly than the oil. If the production rate of the well is low the water will drive all the oil ahead of it through the sand because at this rate of production the sand is able to imbibe the water, "taking the water in at the bottom and expelling oil at the top". However,

Another area of conflict between the majors and the independents is that of import restrictions on oil. With their large supplies of unprorated foreign oil the majors prefer few or no import restrictions.[1] Any reduction of their allowables that occurs because of a greater part of the domestic demand being satisfied by foreign oil is not necessarily a loss to them since often they can make up for any domestic decrease by an increase in their foreign production. Meanwhile the independents, with only domestic markets and domestic supplies, suffer from any cutback in their allowances. One compromise solution to settle this conflict is the method used in the United States where both domestic and imported petroleum are prorated.[2] With this system,

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at a high production rate the pressure around the well is considerably less than in the rest of the pool causing the water front to move so quickly (to the low pressure area) that the sand is unable to imbibe all the water. The result is that the water does not drive the oil, en masse, to the well but instead leaves pockets of oil behind. Thus the oil in the reservoir will be only "partly produced and some remains behind, trapped and lost to production", because of channelling. (A. I. Levorsen, Geology of Petroleum [San Francisco: W. H. Freeman and Company, 1956], p.458).

[1] Sebastian Raciti, The Oil Import Problem, Studies in Industrial Economics, No. 6 (New York: Fordham University Press, n.d.), p.98.

[2] In Districts I-IV, "the level of total imports during each allocation period is restricted to 12.2 per cent of anticipated production of domestic crude and natural gas liquids". (W. J. Levy Inc., The Outlook for Canadian Crude Production and Markets [New York, 1966], p.V-I.)

both the domestic producers and the importers share the burden of over-supply or the benefits of increased demand.[1]

The peculiar demand and supply conditions facing the oil industry provide another key to why prorationing has evolved. "It is perhaps the most important single fact about petroleum production economics that the current additions to producible basic capacity --i.e., reserves--contain a strong random component".[2] Thus, additions to the supply side can be extremely erratic since the relation between a given input (in the form of exploration) and the output resulting from the input (in the form of marketable oil) is very unpredictable and "can only be defined in a statistical sense over many fields and several years".[3] Because of this random element in the extraction of petroleum, changes in the supply, or reserves, are rarely related to changes in demand. Furthermore, the supply side is relatively insensitive to changes in price. In his discussion of the elasticity of supply, Adelman points out that in the short run a producer is unlikely to be

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[1] Raciti, The Oil Import Problem, p.100.

[2] Adelman, The Supply and Price of Natural Gas, p.7.

[3] *Ibid*., p.10.

influenced very much by price changes since, once a well is producing, any further costs are strictly overhead and it is often cheaper to continue producing than to shut down the well. The producer will avoid such a shutdown as long as there is any hope of a price increase in the near future.[1] If, however, such a change does not seem likely, a price that covers short-term extraction costs and the expenses of development activities but not exploration costs will cause a reduction of "medium-term output". A price that covers only the costs of extraction will, if it continues for any length of time, cause a long-term reduction in output. Thus, the supply of oil is price elastic but only in the medium or long run.

The demand side presents quite a different picture from the supply side. Demand, in the short run, does not change unpredictably like supply but instead is relatively constant. Adelman points out that if new reserves and total consumption are plotted on a chart, using a reduced scale to bring the lines together, the line representing the added reserves will swing above and below past the relatively straight

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[1] Another reason for avoiding shutting down a well, even when the price has dropped considerably, is that sand clogging or water encroachment can be so severe as to ruin the well for future production purposes.

consumption line.[1] The only exception to the short-run constancy of demand are the large fluctuations caused by political crises in other major oil-producing areas in the world.[2]

Although the total demand for oil remains relatively stable, changing mostly in response to changes in economy-wide factors such as per capita income, population, consumption, and investment, the demand for particular petroleum products can fluctuate greatly in the short run. On the other hand, the demand for those petroleum products for which there are no substitutes, either because of the particular qualities of the given product or because of the designs of the machines using the product, are relatively fixed and price inelastic in the short run.[3]

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[1] Ibid., p.7.

[2] For example, because of the June 1967 Middle East conflict and ensuing disruptions in the oil exports from that area, the demand for Western Canadian crude jumped from 1,057,929 b/d in June to a record high of 1,146,561 b/d in July. In Alberta the production of crude jumped from 723,400 b/d in June to a record high of 810,251 b/d in July. ("Middle East Crisis Boosts Production", Oilweek July 31, 1967 , pp.14-15).

[3] This statement must be clarified somewhat. The demand referred to here is the economy-wide demand for the particular product. Further, any price changes being considered are those changes that are within a reasonable range of the existing price. For, as Cassady points out when discussing the elasticity of the demand for gasoline, the demand for the product of any one firm is quite elastic and if large changes in price are being considered even total demand will be elastic.

Over the long run, during which time new investments are made and technological changes take place, petroleum products must compete with other sources of energy such as electric power, coal, and nuclear power. Often the various forms of energy are easily interchangeable in the long run and price will be the factor determining which form of energy is chosen. In Imperial Oil's submission of 1963 to the Alberta Oil and Gas Conservation Board they estimate that the portion of the total energy market in Canada in 1975 that will be able to choose between energy forms will be equivalent to the demand for an amount of energy which could be provided by 200,000 barrels per day or 75,000,000 barrels of oil per year.[1] Whether or not this energy demand will be met by petroleum products will be decided by the price of petroleum relative to the price of the other available energy sources.

Often oversupply is given as the most important condition necessitating prorationing. However, another more basic reason is the system of landholding that has arisen in the oil industry. This system, which is often described as a checkerboard system, has resulted in the ownership of single pools of oil being divided

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[1] Imperial Oil Limited, Submission to the Oil and Gas Conservation Board on the Allocation of the Provincial Allowable for Crude Oil (November, 1963), p.8.

among many producers. Each producer's claim to the oil in the pool is determined by the number of wells he drills on his section of land above the pool and at what rate he produces the oil from those wells, i.e., whatever his wells can produce from the pool is his. Since oil is a "fugacious" substance and since the "Law of Capture" holds, without some form of prorationing it is to each producer's advantage to drill as many wells as possible and produce at the fastest possible rate with no thought to the above and below ground waste incurred by too-rapid production. By way of illustration, the following was written in 1921 before prorationing had begun. "The average holding is so small that speed is the owner's sole protection. Let him be careful if he can; let him be economical if he can find a way; but careful or careless, reckless or conservative, he must be speedy if he would survive. The small holding is his master".[1]

The checkerboard system of land ownership is peculiar to Canada and the United States where, unlike in other countries, individuals have been allowed to own subsoil mineral rights. These rights are, or have often

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[1] Joseph E. Pogue, "Economics of the Petroleum Industry," in Elements of the Petroleum Industry, ed. by E. De Golyer (New York: Institute of Mining and Metallurgical Engineers, 1940), p.32.

been, sold in a piecemeal fashion and to many different producers thereby creating the checkerboard system. Even though most governments, for instance the provincial government in Alberta, have since gained control of most of the mineral rights of the land under their authority, the system of selling only relatively small parcels of land to many different producers has continued. It is perhaps because prorationing has removed many of the inequities and wastefulness of a checkerboard system that the piecemeal selling of exploration and drilling rights has continued. Other countries, especially those in the Middle East, have an entirely different approach to land leasing, one which makes the limiting of production to market demands by government regulation completely unnecessary and it seems to work reasonably well. Their system and its relation to prorationing will be discussed more fully later. It is significant that where there is not a checkerboard system of land ownership neither is there prorationing.

CHAPTER II

A BRIEF HISTORY OF PRORATIONING

A. United States

The early history of prorationing is tied very closely to conservation movements in the United States. As early as 1899 laws were passed in Texas governing the operations of producers. These first laws were directed towards insuring that abandoned wells were plugged, that gas was not vented from purely gas wells and that gas was not burnt in flambeau lights.[1] At this time the supply of oil did not exceed the demand with the result that these first laws provided an unsophisticated check only on waste due to careless production methods, not waste caused by overproduction.

It was after the first World War, more specifically in the 1920's, that the supply of oil outpaced demand, resulting in overproduction and waste. At this time too the importance of oil to the national economy

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[1] Wallace F. Lovejoy, "Conservation Regulation: The Economic and Legal Setting," in Essays on Petroleum Conservation Regulation, ed. by Wallace F. Lovejoy and I. James Pikl, Jr. (Dallas, Texas: Southern Methodist University, 1960), p.25.

began to be realized more fully. Simultaneously, a strong conservation movement was beginning. Influenced by a letter written by Henry L. Doherty,[1] one of the leaders in the petroleum industry who deplored the wastefulness of open flow or flush production ("drill-and-produce-as-you-please"), President Coolidge created the Federal Oil Conservation Board in 1924. It is interesting to note that one of the reasons given for creating the Board was that an adequate future supply of oil depended on the fact that the drilling of oil wells remained a profitable venture[2]. It was felt that if over-production could be prevented by the Board, the erratic downward pressure on prices, which made profits uncertain and which might tend to discourage future drilling, would end. Thus, both insuring the profits of the individual producer and conservation were the original reasons for commencing regulation of production in the oil industry.

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[1] Henry Doherty was one of the first strong advocates of compulsory unitization as a means of ending the fantastic waste occurring in the petroleum industry. His plan, which provided for the operation of oil pools as units, became known as the "Doherty plan". (Leonard M. Logan, Jr., Stabilization of the Petroleum Industry [Norman, Oklahoma: University of Oklahoma Press, 1930], p.137).

[2] Erich W. Zimmermann, Conservation in the Production of Petroleum, Petroleum Monograph Series, Vol. II (New Haven: Yale University Press, 1957), p.125.

Once the Board had been created it took a year of fact-finding (by means of questionnaires sent to "everybody who could be expected to help disclose the facts and clarify the issues"[1]), and then a year of hearings before a report was produced for the President. It then took the Board until 1929 to produce even a draft of the legislation needed to circumvent the anti-trust laws and thus allow operators to co-operate in limiting their outputs to meet only current demand. Meanwhile, the over-supply situation in the oil industry had grown even worse. Prices had dropped from the 1920 price of $3.00 per barrel to $1.25 in 1929.[2]

All during the twenties various attempts had been made by the oil-producing states, independently of the federal government and of each other, to restrict output and regulate methods of production.[3] With the exception of Oklahoma, the state governments had very little success in this area. In Oklahoma the

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[1] Ibid.

[2] Ibid., p.115.

[3] For example, "in 1917, the Texas Constituion was amended to declare that conservation of resources was in the public interest and the state had a right and duty to regulate these resources". This amendment opened the way for the Texas Railroad Commission's famous "Rule 37" which regulated the spacing of wells and which was initiated in order to prevent the wasteful drilling of off-set wells. (Lovejoy, "Conservation Regulation", p.25).

regulation of producers was so effective that by the end of 1930 production in Oklahoma had been cut to 12½ per cent of the state's potential.[1] One of the reasons that this enormous decrease was necessary was the chaotic and frenzied production in the rest of the states. Thus Oklahoma suffered for its efficiency and its efforts to stabilize the industry by having the revenues of both the state and the operators severly reduced. But if Oklahoma, like the other states, had permitted unchecked production within its boundaries the waste would have been appalling.

Meanwhile, in Texas in the autumn of 1930, "Dad" Joiner's discovery well opened up the huge East Texas field. Just prior to this important discovery the Texas Railroad Commission had begun to limit the output of the wells in the state to meet market demand. Not fully realizing the enormity of the East Texas discovery the Commission did not start prorating production from the new field until well into 1931 with the result that, under the new regulations, wells which had been producing at a rate of 15,000 barrels per day had to have their production rates cut back to 1,000 barrels per

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[1] Logan, Stabilization of the Petroleum Industry, p.163.

day.[1] Many operators were not prepared to make such drastic reductions. As a result, injunctions were filed against the Texas Railroad Commission, production rates increased, and prices plummeted downwards. Near chaos ensued both in the market and in the oil fields. Finally, in order to restore the peace, the governor declared martial law.

The point of contention was that the proration orders of the T.R.C. were related to market demand, not physical waste. Finally in March of 1932 the situation began to improve when "a Texas court upheld the Commission's order on the grounds that production in excess of market demand caused physical waste and that restriction of output to demand minimized waste".[2] However, the period of conflict had not ended. For one, many of the operators continued to ignore the Commission's orders and the Commission had no way of enforcing the regulations. Furthermore, by refusing to change the very unsophisticated "well basis"[3] of allocating the

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[1] Lovejoy, "Conservation Regulation", p.26.

[2] Ibid., p.27.

[3] Allowances were divided equally amongst all the wells with no consideration given to the amount of land a well drained, the kind of reserves from which the well was producing, etc.

allowables (to some formula that took into account the spacing of a well) the Commission was held in contempt of court and proceedings were instituted against it. Finally the Commission included well potential (although still ignoring well spacing) in the basis for allocation, and the courts upheld its orders. However, the problem of law-breaking operators and their "hot" oil which had caused the system of posted prices to break down completely was not solved until 1935 when the Connally Hot Oil Act was passed. The Act "prohibited the shipment in interstate commerce of oil produced in violation of state conservation laws"[1] . With the Connally Act behind them the Commission was able to force the shippers to prove that the oil they were transporting had been produced legally.

With the exception of the Connally Act all measures taken to control the waste in the oil industry in the United States have been initiated by and are under the control of the state governments. The result of this is that with 32 oil producing states there are 32 different systems of prorationing in the United States.[2]

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[1] Eugene V. Rostow, A National Policy for the Oil Industry, Studies in National Policy (New Haven: Yale University Press, 1948), p.29.

[2] Lovejoy, "Conservation Regulation", p.24.

B. Alberta

Compared to the stormy beginnings of prorationing in the United States the introduction of prorationing in Alberta was a relatively peaceful affair. It was in 1914 that the "Dingman Discovery" opened up the Turner Valley field and an infant petroleum industry made its appearance in Alberta.[1] After the initial flurry of activity caused by the Dingman well, exploration and drilling in the Province continued at a much slower pace until, in 1924, the industry received new impetus when Royalite's No. 4 "blew in". The well, which was also located in Turner Valley, had tapped a deeper and far larger reservior than any previous discoveries and was soon producing naptha, a very high-grade crude, at a rate of 500-600 barrels per day.[2] More wells were quickly drilled and for the next few years production proceeded at an unchecked pace.

Very soon problems arose with regards to the marketing of both the gas and oil produced by the prolific wells in the Turner Valley field. Since the only market for the natural gas was the sparsely settled area of southern Alberta much of the gas produced

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[1] Eric J. Hanson, _Dynamic Decade_ (Toronto: McClelland and Stewart Limited, 1958), p.43.

[2] _Ibid_., p.47.

was flared, at a rate of several hundred million cubic feet per day, in order to procure the condensates contained in the gas. The market for oil was also very unsatisfactory for the producer. The existing pipelines and refineries could not begin to handle all the crude being produced with the result that the refiners set up a system of quotas for deciding the amount that a refinery would receive from each well. Many of the producers were dissatisfied with the control thus exercised by refiners. Since the refiners were equally unhappy with the unpopular role of arbitrator they had to play, both groups requested that the government take over the responsibility of assigning quotas.

Coupled with the dissatisfaction of the producers and refiners was a growing concern for the tremendous waste being incurred by the unscientific methods of production being employed by many of the operators.[1] The intergrated companies had not been able to persuade the smaller, independent producers to use more scientific production methods. The independents

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[1] It has been estimated by Oilweek that over a billion dollars worth of gas and oil was wasted through careless aboveground techniques, and that over 400 million barrels of oil are trapped in the reservoir and are unrecoverable because of the pressure lost by the unregulated flaring of gas and producing of oil. (James M. Freeman, Biggest Sellout in History: Foreign Ownership of Alberta's Oil and Gas Industry and the Oil Sands [n.p.: Alberta New Democratic Party, 1966], p.89).

feared that if they did co-operate much of the oil under their land would be diverted to the wells of the larger, integrated producers who had quaranteed access to refining facilities and markets.

As a result of the growing concern and the demands of the industry the provincial government set up the Petroleum and Natural Gas Conservation Board in 1938 under the Oil and Gas Conservation Act of the same year. Under the Act the Board was to "prevent the waste of the oil and gas resources of the Province" and "afford to each owner the opportunity of obtaining his just and equitable share of the production of any pool"[1]. Given these powers, the Board was immediately able to assume the responsibility of assigning a quota to each well so as to limit production to market demand, and of imposing conservation measures on all producers. The latter was done by estimating the rates of production for each well which would lead to the greatest ultimate recovery of the oil from a particular pool. These rates were known as "maximum permissible rates" or MPR's[2] and no well was allowed to operate above them (except under very special

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[1] Oil and Gas Conservation Board, Report and Decision on Review of Plan for Proration of Oil to Market Demand in Alberta (July, 1964), pp.12-13.

[2] These will be discussed more fully later in the paper.

circumstances).

In 1939, with the start of World War II, the demand for Canadian crude increased greatly. As a result, the Board no longer had to assign quotas and, for the next eleven years, its function became solely that of enforcing good engineering practices in the production of oil.

In 1947 the supply picture was radically changed by the discovery of a major new field at Leduc. In 1949 another prolific discovery was made at Redwater with the result that even with production limited by the Conservation Board's "maximum permissible rates" the provincial potential greatly exceeded the available demand. At first a voluntary system known as the "well-acceptance" or "pipeline-acceptance" system of limiting production was attempted. Since the total of the "well-acceptances" was considerably less than the market demand the system soon became inoperable. The purchasing companies gave the producers no quarantees that they would buy the same amount each month from each field. Even more serious were the uneven production rates that occurred within a producing pool, adversely affecting both the leaseholders and the royalty owners in the long run. Since the fields were in areas where Government royalty land was intermingled with freehold royalty land, all parties, "producers, refiners, landowners and

Government were deeply concerned about a potentially chaotic situation, and it was industry itself which requested the Oil and Gas Conservation Board to take control".[1] This the Board did in December of 1950.

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[1] Charles S. Lee, "Allowables and Allowances" (paper presented at the 14th Annual Meeting of the Canadian Institute of Mining and Metallurgy, Edmonton, Alberta, April 1, 1963), p.2.

CHAPTER III

PRORATIONING IN ALBERTA
PAST AND PRESENT SYSTEMS

A. The Initial System, 1950-1957

The system of prorationing devised in 1950 by the Conservation Board was used, with only a few modifications, until 1957. Each month the Oil and Gas Conservation Board held hearings where nominations from the purchasers of crude were received. The total of these nominations then represented the "provincial allowable".

For the first five years of the plan the total was then divided into three categories, light, medium, and heavy crude[1] according to the demand for each type from the purchasers. Since the demand for heavy crude always exceeded the provincial productive capacity there was never any need to prorate this type of oil. The division of the rest of the allowable into the light and

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[1] A crude is designated as being light, medium, or heavy according to its specific gravity. Usually a scale introduced by the American Petroleum Institute is used. On this scale a light crude's specific gravity will be about 50.0° API while a heavy crude's is about 20.0° API.

medium crude categories was often difficult since the defintion of medium crude was fairly arbitrary. As a result, borderline cases were allocated at the discretion of the Board. By 1955, because of the predominance of light crude discoveries (both in number and in volume), and because of the fact that the expansion of the pipe line gathering systems led to more blending of the varying grades of crude produced from different pools, the need for dividing the crude into light and medium categories was removed. Hence it is the prorationing of "light crude" production that is discussed in this chapter.

Once the provincial allowable had been determined for the particular month the next task was to divide this amount amongst the pools. A pool's share was decided by means of a formula that consisted of two parts. The first of these was called the "economic allowance". Mr. McKinnon, the Chairman of the Board in 1950 stated that the economic allowance combined "the idea of a 'depth factor' (which has been proposed to compensate for the pay out of drilling costs) and the concept of a 'floor' (which has been proposed as compensation for operating expenses)".[1] Thus the economic

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[1] Oil and Gas Conservation Board, Plan for Proration to Market Demand (December 1, 1950), p.5.

allowance was the part of the proration formula that was based on cost considerations and which insured that the amount of oil that a well would be allowed to produce would cover the costs of drilling and completion, and also the costs of operating the well. Hence the size of the allowance allocated to a well varied with the depth of the well. The minimum allowance assigned to wells in the shallowest pools, was thirty barrels per day while the maximum, for those wells drilled to depths greater than 8,000 feet, was fifty barrels per day.[1]

The total of the economic allowances assigned to the pools throughout the Province was then subtracted from the total provincial allowable. The remainder then represented the prorated share, or the residual demand as it was more commonly called. This part was then allocated to each pool on the basis of the percentage that each pool's producing potential constituted of the total provincial potential. (The total provincial potential was equal to the sum of all the pools' potentials.)

A pool's producing potential was spoken of in terms of its MPR or Maximum Permissible Rate. This term was defined by the Oil and Gas Conservation Board as the

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[1] Oil and Gas Conservation Board, Report and Decision, p.41.

Board's estimate of the "maximum rate at which oil can be produced without avoidable underground waste".[1] The Board's estimate of the MPR was based on a formula which accounted for such factors as the thickness of the pay zone, the acreage tapped by the well (or the spacing of the well), the nature of the reservoir drives, the expected recovery and life of the pool, and other variables such as the amount of connate water, the porosity of the oil-bearing stratum, the reservoir pressure, the producing gas-oil ratio and the producing water-oil ratio.[2] The MPR then, was that part of the proration formula which was based entirely on conservation principles and sound engineering practices.

The MPR for a pool or well was tentatively set when the first discovery was made. As more data and information were gathered, and as more wells were drilled in the area, the Board revised its original estimates to reflect more accurately the conditions existing in a pool. Since some of the variables, such as the recovery life factor, necessarily changed over time there was always a need for constant revision of a

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[1] *Ibid.*, p.10.

[2] See Appendix No.II for the exact formula used to find the MPR of a pool.

pool's MPR.

If a pool's MPR exceeded its economic allowance, it received a share of the provincial residual demand. Those pools whose economic allowances exceeded their MPR's produced at their maximum permissible rates with the remainder of their economic allowance being added to the size of the residual demand to be distributed amongst those pools with MPR's greater than their economic allowances. The sum of a pool's economic allowance and its prorated share, i.e., its share of the provincial residual demand, equalled its market allowance.

By way of illustration, if there were an increase in the number of wells drilled and producers' nominations remained constant, there would be an increase in the total of economic allowances being subtracted from the total provincial allowable. As a result, any well which had previously been receiving part of the provincial residual demand would now receive a smaller market allowable since, with the new wells claiming their economic allowances, a smaller part of the total provincial allowable would remain as the prorated share. If, however, there were very few or no new discoveries and the demand for Alberta oil increased, then the market allowances of the pools (via an increase in the size of the prorated share to be distributed) would be increased. The allowances could also be greatly affected, assuming a constant or only slowly

increasing demand, by the extent and quality of any new discoveries. For example, if a newly discovered pool had a very high MPR the percentage of the Province's total "producibility" contributed by the existing pools would decline, causing a decrease in the percentage of the residual demand they would receive. A simple numerical illustration may help to clarify the above example.

TABLE I

	Provincial Producibility	Producibility of Pool A	A's Producibility as % of Provincial Total
Time t	10 b/d	1 b/d	10 %
Producibility of New Discovery	2 b/d		
Time t+1	12 b/d	1 b/d	8.3%

From the table, it can be seen that a new discovery would cause a decrease in the percentage that A's producibility represented of the provincial total, and thus a decrease in A's share of the provincial residual demand. If it is assumed that total demand remained constant, this

would then mean a reduction in A's market allowance.

Other adjustments could affect the size of the allowance. For example, if a producer allowed production from a well to exceed the assigned allowable by 10 per cent he would be penalized by having his quota reduced in the following months. Penalties were also imposed if good engineering practices were not followed, i.e., if excessive production of gas or water occured, causing unnecessary and harmful changes in the gas/oil or water/oil ratios.[1] If underproduction occurred, up to 20 per cent of a month's allowable could be carried over to the following month. If for exceptional reasons such as inadequate pipeline or storage facilities or blocked roads a producer was forced to produce less than his allowable, the Board would permit a carry-over of greater than 20 per cent of one month's allowable to the next.[2]

B. Revisions Made in the System, 1957-1963

The system of prorationing briefly described above was used from 1950 to 1957. In 1957, following

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[1] An excessive gas/oil ration was defined originally as 1,000 Mcf. of gas per barrel of oil but later was allowed to vary from field to field at the discretion of the Board. An excessive water/oil ratio was any ratio greater than .02 barrels of water per barrel of oil. (Lee, "Allowables and Allowances", pp.6-7).

[2] Hanson, Dynamic Decade, p.207.

representation from the industry, the Board decided to call a hearing to review the proration plan and to provide an airing of the grievances expressed by many of the companies. Since many of the proposals and complaints put forward at the 1957 hearings expressed views very similar to those heard in 1963, the various conflicting opinions and proposals will be discussed more fully below in connection with the 1963 hearings.

Three major changes were made after the 1957 hearings. The Board felt that there was "very little justification for the indefinite continuance of an economic allowance which would permit the several fold recovery of drilling costs"[1], so decided to adopt a "two stage" economic allowance. The first stage was called the initial economic allowance and was designed to cover operating costs, a five-year payout of drilling costs, and a two and a half-year payout of completion costs. It varied from 30 barrels per day for the shallowest pools to 190 barrels per day for the deepest.[2] The second stage, which applied after the pool had been

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[1] I. N. McKinnon, The Proration Plan and the Economic Allowance, Oil and Gas Conservation Board, (August 30, 1957), p.1.

[2] Oil and Gas Conservation Board, Report and Decision, p.44.

operating for seven years, was called the operating economic allowance and was intended to cover only the costs of operating a well plus the continuation of the two and one-half year payout of completion costs. In contrast to the initial economic allowance, the operating allowance varied from 25 barrels per day to only 73 barrels per day.[1]

All fields brought into production after January 1st, 1958, were assigned the initial economic allowance which was to be reduced later to the smaller operating economic allowance. On January 1st, 1962, all fields which had been in operation for more than seven years had their old economic allowances reduced to the new, smaller, operating economic allowance. It is interesting to note that in spite of the Board's intention to end a system of economic allowances that permitted "the several fold recovery of drilling costs", the new formula still allowed drilling costs to be recovered one and a half times while completion costs would be returned many times over, the number of times depending only on the life of the well.

The net effect of the change in the formula for the economic allowance was an increase in the amount of the total provincial market demand being allocated on

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[1] *Ibid*.

the basis of a well's producing potential, i.e., the relative size of the prorated share was increased. This shift is clearly illustrated by the following table:

TABLE 2

	December 1961	March 1962
Actual Provincial Market Demand	484,000 b/d	492,000 b/d
Economic Allowance	441,000 b/d	365,000 b/d
Allocation Factor to Residual Demand	0.0947	0.2662
Number of Wells	10,641	10,831

Source: Charles S. Lee, "Allowables and Allowances", p.9.

From the table, it can be seen to what extent the change in the economic allowance benefited those producers in the higher potential fields to the disadvantage of those in the lower potential fields.

Another change made after the 1957 hearing was in the formula used to distribute the residual demand. The new formula, which became known as the "allocation factor" is given below.

$$\text{Pool Allocation Factor} = \frac{\text{Pool MPR} - \text{Pool Economic Allowance}}{\text{Provincial MPR} - \text{Provincial Economic Allowance}}$$

Previously the equivalent to the pool allocation factor would have been simply $\frac{\text{Pool MPR}}{\text{Provincial MPR}}$. With this change, then, the complete formula deciding the total allowance to be allocated to a pool could be written as follows:

$$\text{Pool Allowance} = \text{Pool Economic Allowance} + (\text{Total Provincial Residual Demand} \times \text{Pool Allocation Factor}).$$

This system of allocation became known as the Residual MPR plan and became effective January 1st, 1960.

The significance of the above change was that it eliminated a form of double-counting. For example, if a well's MPR equalled its economic allowance, under the old formula it would still be entitled to a small part of the provincial residual demand. Since the well would not be permitted to produce at a rate above its MPR its share of the provincial residual demand that it received would have to be returned and be reallocated amongst the rest of the pools whose MPR's exceeded their economic allowances. With the new formula a situation such as the above where a well is being given an allowance that is greater than its MPR is eliminated (except in the case where even the economic allowance exceeds the well MPR).

During the 1957-1963 period a situation arose which introduced problems that could not be easily solved

by the rules outlined in the existing proration plan. It was the question of economic allowances for "non-producing" wells. Wells of this kind occurred in enhanced recovery schemes (in the form of injection and observation wells) and in units operations (in the form of wells which were shut in). It was argued on the one hand that, since injection and observation wells were just as necessary to a secondary recovery project as the production wells, they should receive an economic allowance which could be transferred to the producing wells. In the case of unitized projects, where some wells were shut in it was argued that it was not equitable to penalize producers for organizing units operations. On the other hand it did not seem logical to credit the unit with full economic allowances to cover costs, only part of which had been incurred, or which had never been incurred at all. Similar to this problem was the question of multi-zone wells. Should the one multi-zone completion receive the sum of the economic allowances of the zones it encompassed?

In September of 1961 the Board announced its decision. The economic allowance of a unit or project would be the sum of

"a) for production wells, the lesser of the subsisting economic allowance or current physical productivity, and

b) for injection and observation wells, the subsisting economic allowance if the well is necessary to the scheme, would have been

> capable of commercial production, and would have qualified for an oil allowable, and subject to the Terminal Transfer Policy."[1]

It was this last "subject to the Terminal Transfer Policy" that created much discussion in the industry. It is interesting to note that at the 1961 hearing only one company was in favor of the Terminal Transfer Policy while 22 were against it.[2]

Under this policy the Board permitted the transfer of economic allowances of certain wells under certain circumstances for a limited length of time. The length of this period for each well was to be set at the discretion of the Board, the Board using as its base a point in time when the cumulative depletion which corresponded to a predetermined gas/oil ratio penalty level was reached. Since this estimate of when the primary recovery stage of a pool would end represented a very hypothetical and unprovable point in time, many of the companies involved disagreed with this policy. They argued that since secondary recovery was likely to increase the theoretical productivity of the pool, and hence of all the wells in the pool including the

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[1] Oil and Gas Conservation Board, Report and Decision, p.43.

[2] Lee, "Allowables and Allowances," p.10.

injection wells, a terminal transfer date which was based on primary depletion was not just. Furthermore, they argued that it was the ability to transfer allowables that made the initiating of secondary recovery projects financially attrative. Therefore, they felt the transfer of allowables encouraged conservation.

In the case of a multi-zone well, the Board decided after a hearing in 1960 that the well would be assigned "the economic allowance for the zone having the highest MPR and for each other zone the well would be assigned a lesser allowable prescribed according to certain rules".[1]

C. The New Proration Plan, 1965- ?

1. Introduction

Many of the points of dissension and faults contained in the proration plan were either not removed or not improved by the various changes made in the plan during the period 1957-1963. As a result, in spite of all the many hearings held in the recent past, the Board decided to call another hearing for November of 1963 in order to review the proration plan in its

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[1] Oil and Gas Conservation Board, Report and Decision, p.46.

entirety. Submissions from all interested parties were requested. They were to deal with either specific areas of the plan or with all aspects of the existing system. Seventeen submissions were received.

In the report that was published by the Board at the conclusion of the hearings, in which they outlined the changes to be made in the proration plan as a result of those hearings, the Board enumerated the objectives which they felt a proration plan should attempt to meet. These objectives were divided into two categories, those which were contained in the provisions of the Oil and Gas Conservation Act[1] and those which the Board and, generally, the participants at the hearing felt should be met by the new proration plan. The first group of objectives are summed up by the following two directives: "the prevention of waste and the conservation of the Province's oil and gas resources"[2], and "the giving to each owner the opportunity of obtaining his just and equitable share of the oil in the pool"[3]. In as much as the system of prorationing should

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[1] They are found in Section 4 and Section 36 of the Act.

[2] Oil and Gas Conservation Board, Report and Decision, p.23.

[3] Section 4, clause (d) and section 36, subsection (1), clause (c) of the Oil and Gas Conservation Act.

prevent waste and conserve the Province's oil supply the Board felt that the following objectives, by encouraging the industry to maximize the recovery of oil were, in effect, also part of the group of objectives contained in the statute. These objectives, which are taken from the report of the Oil and Gas Conservation Board are listed below:

> "1. To encourage efforts to enhance the recovery from pools,
>
> 2. To discourage the abandonment of wells before the production of all apparently economically recoverable oil,
>
> 3. To assure production from low reserve per acre discoveries which appear economically recoverable."[1]

Other objectives that the Board felt were desirable were as follows:

> "1. To provide a system which is relatively simple to administer,
>
> 2. To provide a method of allocation operable over a wide range of market conditions, both as to supply and demand, and allow continuity in the production from and development of pools,
>
> 3. To encourage exploration and not deter any party interested for exploring from new reserves,
>
> 4. To maintain the participation in the industry by anyone interested,

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[1] Oil and Gas Conservation Board, Report and Decision, pp.23-28.

5. To encourage the economic optimum development within pools, and minimize the cost of oil."[1]

The Board realized that it would probably be impossible for one formula to meet all these objectives, and that not all of them could be considered as prime objectives. Its intention was, therefore, to choose that proration plan which first met the list of objectives contained in the Statute and then as many as possible of the others.

At the beginning of the Report the Board lists five faults of the existing system. These were, very briefly, that the system encouraged the drilling of unnecessary development wells, that it provided insufficient incentive for achieving maximum recovery of a pool by means of enhanced recovery schemes and for exploring for new reserves, that it was complex to administer and, finally, that it increased operating costs.

In an attempt to correct these faults and to meet the objectives, the Board made many changes in the existing proration plan. In order to understand the significance of these changes it will be necessary to discuss each of them in turn, stating first why they were made and then what the possible alternatives were. This discussion will be limited to those changes which can be considered to have had a major impact on the various producing companies in the industry.

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[1] _Ibid._, pp.31-38.

2. Changes in the Minimum Allowance

One of the most important changes made by the Board was in the whole system of economic allowances. Whereas in the old system the economic allowance was in the form of a basic allowance, under the new plan it became a floor allowance. There were distinct differences between the two systems. Under the old system, once total provincial demand was ascertained the fraction of this demand that was needed to satisfy the economic allowances of the pools was allocated first, with the remainder of the demand then being allocated on the basis of other factors, such as MPR's or reserves. With a floor allowance the total provincial demand is first allocated on the basis of the other factors. Once this has been done, any pool which is found to have been allocated an amount that is less than the floor allowance to which it is entitled has its allowance increased to the level of the floor allowance, while those pools with allowances greater than their floor allowances receive proportionately less.

Having decided to adopt a floor allowance the Board drew up a schedule of floor allowances based on the depth of a well and independent of the area drained by the well. The schedule was designed to allow the producer to recover completion and operating costs and to earn a reasonable return on the investment in completion costs. However, no allowance was made for the recovery

of drilling costs as had been done in the previous plan. Furthermore, the floor allowance was to be applied only to producing wells and was not transferable. In the case of segregated multi-zone completions, the floor allowance was to be equal to the sum of the allowables that would have been allocated if separate wells had been drilled to each zone.

The Board gave several reasons for changing from a basic allowance to a floor allowance. First, the Board wished to make the allowance large enough to encourage the completion and operation of wells drilled on marginal reserves and also to prevent the premature abandonment of wells. However, it felt that the allowance should not be so large as to provide the incentive for drilling unnecessary wells or so large as to provide an incentive for exploration.

The Board chose a floor plan over a basic allowance system since it felt that the floor plan could adequately meet the objectives of a minimum allowance, i.e., to prevent the premature abandonment of wells and to permit production from wells on marginal reserves, while leaving a larger share of the provincial demand to be allocated on the basis of reserves or related factors. Furthermore, the Board preferred the floor allowance system "since with it any fluctuations in demand are reflected almost equally on a percentage basis in

all allowables above the floor level".[1]

Since the new minimum allowance was designed to cover only completion and operating costs it was logical that it should only be applied to producing wells and not be transferable. The Board did not use acreage drained by the well, as well as the depth of the well, as one of the factors deciding the floor allowance for two reasons. First, the only justification for the minimum allowance was to cover the costs of producing and, secondly, the acreage factor would be accounted for in the rest of the allowable formula.

At the November hearings many other views were expressed as to the form the economic allowance should take. These views ranged from the suggestion made by Imperial Oil to have a fixed floor allowance (of 7 barrels per day regardless of depth) to be assigned to old pools only[2], to the suggestion made by IPAC to have a basic allowance which would range from a minimum of 50 barrels per day for the shallowest wells to 110 or more for the deepest wells. This considerable range in the

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[1] Oil and Gas Conservation Board, Report and Decision, p.69.

[2] Imperial Oil Limited, Submission to the Oil and Gas Conservation Board on the Allocation of the Provincial Allowable for Crude Oil (July 31, 1963), p.13.

size of the suggested minimum allowances reflected the varying opinions on what the major objectives of an economic allowance should be. For example, IPAC felt that the economic allowance assigned to a well should be large enough to provide a return that would encourage future exploration.[1] Others, such as Pan American, Imperial and Texaco Exploration, wanted the economic allowance retained at a minimal level in old pools (and with no economic allowance for new ones) strictly as a means of phasing into a plan with no economic allowances.

Other suggestions proposed that the size of the allowance should be dependent on the productive area, as well as depth. The justification for introducing the acreage factor was that it would discourage the drilling of unnecessary wells in order to gain the extra economic allowances and would encourage wider spacing units. Hence, those producers who chose to drill one well on a larger area, instead of a possible two or three wells, would not be penalized in the form of a smaller total economic allowance for drilling fewer wells. The justification, however, for including an acreage factor was removed by the Board's setting the minimum allowance at a level which did not cover drilling costs.

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[1] Independent Petroleum Association of Canada, Submission to the Oil and Gas Conservation Board Concerning the Prorating of Oil Production to Market Demand (July 30, 1963), p.3.

3. Changes in the Method of Allocation Between Pools

The next major change to be discussed was the basis to be used for allocating the provincial demand among pools. In the previous plan the MPR or productivity of a pool was used as the basis. The maximum permissive rate of production for a pool was equivalent to the estimate of the pool's ultimate reserves divided by the estimated uniform rate life of the pool.

The reasons the Board gave for changing the allocation base were several. The Board felt that, since the MPR of a pool reflected the developed productivity of the pool, the use of the MPR as a means of allocating provincial demand tended to encourage the development of unneeded productivity. Furthermore, the inclusion of the life factor modifier, part of the formula for estimating the MPR, tended to discourage the development of low permeability pools, particularly those with low reserves per acre. In addition, the Board found the life factor modifier very difficult to estimate "on a sound technical basis".[1] Since with the new system of minimum allowances adopted by the Board this factor would play a much larger role in deciding the total allowable for each pool, the Board felt that

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[1] Oil and Gas Conservation Board, Report and Decision, p. 103.

under the new sytem it would be wiser not to retain such a controversial measurement.

The different proposals put forth at the hearing suggesting changes in the basis of allocation could be divided into two categories: allocation on the basis of ultimate reserves versus allocation on the basis of remaining reserves. The Board decided, as a means of combining the advantage of both systems and minimizing their disadvantages, to use a composite pool allocation base in which the ultimate reserves and the remaining reserves of a pool would be given equal weighting. This composite base was, then, "mathematically equivalent to using the pool's ultimate reserves less 50 per cent of its cumulative production".[1] The ultimate reserves of a pool would be assessed each year at public hearings held during February, and the pool's allocation base would be adjusted at the same time to account for the additions made to its cumulative production during the preceding year.

A system using ultimate reserves as its base is one in which the pool's share of the provincial demand is determined by the ratio of the pool's ultimate reserves to the Province's ultimate reserves (assuming

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[1] *Ibid.*, p.175.

that there are no minimum allowances and no limitations on the rates of production). Those in favor of an ultimate reserve system argued that such a system contributed to conservation since the "application of optimum recovery techniques"[1] would be rewarded. For example, as a pool became depleted and its allowable approached or even exceeded its existing productive capacity, the producer, being unwilling to return part of his assigned allowable owing to the pool's lack of productive capacity, would instead attempt to maintain or even increase the productivity of the pool. This he would do either by drilling more wells or by initiating an enhanced recovery scheme. The supporters of the ultimate reserve system also felt it would be a simple system to administer, particularly since it would be "workable over a broad range of market demand"[2]. They argued that their proposed system would encourage exploration since it would guarantee high rates of return on prolific discoveries. Furthermore, such a system had the advantage, by approximating a uniform pool life regardless of the volume of the pool's reserves, of

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[1] Socony Mobil Oil of Canada, Ltd., Submission to the Oil and Gas Conservation Board on the Proration of Oil Production to Market Demand (July 31, 1963), p.3.

[2] Province of Alberta, Oil and Gas Conservation Board, Proceedings, Proration of Oil Production to Market Demand, Vol. 1 (Calgary: November 5, 1963), p.32.

equalizing the gross present worth of each barrel of recoverable oil at the time of the pool's discovery.

The strongest criticism of those who opposed an ultimate reserve system was that, unlike a remaining reserve system, an ultimate reserve system of allocating allowables was unrelated to the ability to produce. Furthermore, it was suggested that, by not relating the allowables to the ability to produce, infill drilling would be encouraged as a pool's productive capacity declined. This would cause an unnecessary increase in the costs of production.

Many of the advantages and disadvantages, listed above, of an ultimate reserve system would depend for their relevancy on the trend in the allocation factor. In the case of an ultimate reserve system the allocation factor is defined as the ratio of the provincial allowable to the provincial ultimate reserves. If the allocation factor were to remain relatively constant, i.e., the ratio of demand to reserves was stable, then the claim that an ultimate reserve system would achieve uniform pool lives and the claim that the allocation to a pool could exceed productive capacity and thus be an encouragement to infill drill would both be true. The latter claim would also be true if the trend in the allocation factor were upwards, i.e., demand increased at a faster rate than the additions to reserves.

If remaining reserves are used as the basis for allocation, then the fraction of the provincial allowable that will be received by a pool will be equal to the ratio of the pool's remaining reserves to the provincial remaining reserves, disregarding minimum allowances and any limits on the rates of production. Under this system the allocation factor becomes the ratio of the provincial allowable to the provincial remaining reserves. Hence, this formula theoretically leads to a pool's receiving an ever-diminishing allocation and to having an infinite life.

When using a remaining reserve system, two adjustments must be made reasonably frequently in order to insure that the remaining reserve figure credited to a pool reflects what acutally exists. These adjustments are, (1) changes in the ultimate reserve figure that become necessary because of changes in reservoir properties and in the recovery factor and, (2) the necessary change in the cumulative production figure.

One interesting aspect of using a remaining reserve system is that, assuming no minimum allowances, "production is allocated to pools in such a manner that at any point in time each pool's life index is equivalent to the overall provincial life index".[1] This

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[1] Oil and Gas Conservation Board, Report and Decision, p.104.

means that the life of a pool is, theoretically, extended to that point in time when all the Province's reserves are exhausted, assuming no minimum allowances or any limitations on the maximum rate of production. If, however, a minimum allowance is introduced, then it prevents the unreasonable extension of a pool's life and the possibility of an allocation being so small as to make a pool uneconomic in the later years of the pool's life.

The proponents of a remaining reserve scheme cited a number of arguments to support their proposal. They emphasized that such a scheme insured consistency between the size of the allocation allotted to a pool and the pool's productive capacity. Because any increases in reserves (including additions to reserves made both by new discoveries and by the introduction of enhanced recovery schemes) would receive high initial allowables, they felt that a remaining reserve scheme would encourage both exploration and the initiation of secondary recovery projects, more so than an ultimate reserve system.[1] The proponents of the ultimate reserve system conceded that the above would probably be true.

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[1] Shell Canada Limited, Submission to the Oil and Gas Conservation Board of the Province of Alberta Regarding Proration of all Production to Market Demand (July, 1963), p.6.

The critics of a remaining reserve scheme argued that such a scheme would be more complex to administer than an ultimate reserve system. They felt that the high allocation awarded a pool at the beginning of its life would encourage a producer to develop greater capacity than would be justified by the decreasing allocation the pool would receive for the remainder of its life. However, whether or not a pool's allocation would necessarily be decreasing significantly over time would depend on the trend in demand and in additions to reserves, i.e., the trend in the allocation factor. Furthermore, it was felt by the supporters of the remaining reserve system that, regardless of which system was used, surplus capacity, in the form of extra wells, would be installed in a new pool because of the necessity of delineating the new pool, providing efficient drainage, and safeguarding correlative rights.

The fact that all pools, regardless of the dates of their discovery, would have the same remaining years of life did not seem reasonable to the critics of the remaining reserve system. Furthermore, it seemed unreasonable that, unless a minimum allowance was introduced, the life of a pool could be extended for an unrealistically long period. Even though a minimum allowance was very likely to be incorporated in the whole proration plan, they felt that its size and pur-

pose should not be related to the necessity of preventing any such elongation of the life of a pool.

The Board's major criticism of the remaining reserve system was that under this system, because of the large allocations being claimed by any new reserves discovered during a given period, any increases in provincial demand would not necessarily be shared amongst all pools. A situation could even arise where, because of large additions to reserves, many pools would receive less than their previous allocation, possibly even with an increase in demand that was proportionately greater than the increase in either ultimate or remaining reserves.

4. Changes in the Method of Allocation Within a Pool

Once the allocation to each pool has been decided upon, the next step is to divide the pool allowable amongst the wells in the pool. The need to divide up the pool allowable occurs only in those pools or portions of pools where there are non-unit wells engaged in primary production and/or where there is more than one enhanced recovery scheme in operation or more than one unit in operation. The Board chose an "area method modified by recovery factor for portions of a pool subject to different enhanced recovery

mechanisms"[1] as the allocation base to be used in distributing a pool allowable amongst the wells in the pool.

It was suggested by one firm that the only equitable way to divide up a pool allowable would be by using the same method used for allocating allowables between pools. Only this firm felt that this consistency was of any importance. The proposals made by the other firms as to possible bases that could be used can be divided into two categories, those supporting an ultimate reserves method and those in favor of an area method.

Using an ultimate reserves method, a well receives a share of the pool allowable equivalent to the fraction of the pool's ultimate reserves that are attributed to the particular well.[2] To ascertain the reserves attributable to a particular well the following factors must be determined:

(1) the area allocated to the well,

(2) the average thickness of the pay zone throughout the assigned area,

(3) the average values of connate water, porosity, and formation volume factor effective for the volume that was determined by multiplying (1) and (2), and

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[1] Oil and Gas Conservation Board, Report and Decision, p.127.

[2] This definition assumes that there are no minimum allowances and no limitations on a well's production rate.

(4) the recovery factor effective over the volume as defined by (1) and (2).

The proponents of the ultimate reserve system felt that since this system would allow each well to produce all the reserves underlying it and thus guard against lease-line drainage it would be the most equitable method of allocation. The critics of the system pointed out that this "advantage" would only exist for those pools in which all wells had productive lives of equal length. If the lives of the wells differed, as in fact they do in pools which have bottom water drives or which are inclined and subject to expanding gas cap drives, then the wells would not necessarily receive an amount equal to their underlying ultimate reserves.

The complexity, difficulty, and expense of estimating the ultimate reserves for each individual well was also cited as a distinct disadvantage to using the ultimate reserve system. Furthermore, it was pointed out that if, as is often the case, the variables are fairly uniform throughout a pool so that using averages for the pool is not unreasonable, then the allowables found by using the ultimate reserve method will equal those found by using an area method.

Under the area method a well receives a fraction of the total pool allowable equal to the fraction of the total pool area that is attributable to the parti-

cular well.[1] The total pool area is defined as the total of the areas that are allocated to the wells in the pool.

Under the previous plan the area attributable to a particular well was equal to the spacing unit that was assigned to the well for the purpose of drilling and producing oil, an area generally equal to a quarter section. Feeling that greater flexibility in well spacing would minimize costs the Board decided to initiate a dual spacing unit system in the new plan. The first type of spacing unit, the drilling spacing unit, was in most cases to be equal to the old spacing unit of a quarter section and was to be defined strictly in connection with the drilling of a well. The second type of unit, the production spacing unit, was to be for production purposes only. The area of this unit was to be very flexible. Its size would depend on the number of drilling spacing units surrounding the original drilling spacing unit of the well that showed clear evidence of recoverable oil underlying them. Hence one well could conceivably have a production spacing unit equal to two and one-quarter sections, i.e., nine quarter sections. Only complete drilling spacing units,

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[1] Here again it is assumed that there are no minimum allowances and no limitations on production rates.

under common ownership, contiguous to the original spacing unit, and lying "more or less directly between productive wells separated by not more than one or two miles"[1] would be considered in forming a production spacing unit. Furthermore, for a producer to receive approval for a proposed production unit, he had to demonstrate to the Board, by geological and other evidence, that in fact the contiguous drilling units did contain oil which could be recovered by the well in the central drilling spacing unit.

In summary then, the area allotted to a particular well in a pool would be equal to at least one drilling spacing unit and would be greater than this if the producer were able to form a production unit made up of contiguous drilling spacing units. The advantages to the producer of being allowed to organize production units and also some of the problems that have arisen from this innovation in the prorationing system will be discussed later.

When using the area method for allocating the allowable within the pool various reservoir properties, such as the average pay thickness or the porosity over the allocated area, or a recovery factor (defined below)

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[1] Oil and Gas Conservation Board, Report and Decision, p.179.

may be introduced as modifications to the straightforward area method. If some of the reservoir properties are incorporated, then the area method approaches the ultimate reserve method. As a result, only the incorporation of a recovery factor was considered.

The proponents of the area method felt that its greatest advantage was its simplicity. It removed the need for the Oil and Gas Conservation Board's interpreting complex sub-surface data for each individual well. Also it could be applied to all the many types of pools that come under the prorationing system. Another advantage was that, in pools where some of the wells had shorter productive lives than the others, the area method provided a better opportunity than the ultimate reserve method for these shorter lived wells to produce the reserves attributable to them.

Those who were against the use of the area method pointed out that, while in pools with fairly uniform characteristics the area method would equate the aggregate production of a well with the ultimate reserves attributable to the well, it would not do so in cases where the properties of the reservoir were not consistent throughout its area.

The recovery factor, which was included in the formula by the Board, was introduced in order to achieve a more equitable distribution in those pools where more

than one recovery mechanism was in operation. Its inclusion was designed also to encourage more efficient enhanced recovery schemes. The recovery factor takes into account the expected uniform rate life of a well and the expected recovery from a well. Hence, if an enhanced recovery project both increased the expected life and the expected recovery of a well, an area method modified by a recovery factor would take into account and reward these changes brought about by the initiation of the secondary recovery project.

5. Summary of the Present System

In summary, the present proration system can be divided into three parts. First, the Oil and Gas Conservation Board holds hearings each month. At these hearings the refiners make their nominations, i.e., their estimates of their demands for crude for the following month. The refiners' nominations for light and medium crude, when totalled, equal the provincial allowable that is to be prorated among those pools producing light and medium crude. Next, the Board allocates the provincial allowable to the pools in the Province on the basis of reserves. Finally, the pool allowable is allocated to the wells within the pool on the basis of area. This, then, in a very simplified form, is how the market demand for crude oil is allocated amongst

producers in Alberta.

In order to condense all the information contained in this chapter and in order to facilitate a discussion of the effects of the changes made in the proration plan, a summary of the significant differences between the present and the previous plan follows. The two-stage economic allowance of the previous plan, which was designed to cover drilling, completion and operating costs, was replaced by a basic floor allowance that was designed to cover only completion and operating cost. In the previous plan, allocation among pools was done on the basis of the pools' MPR's, which were equivalent to using ultimate reserves modified by a life factor. In the new plan, a composite pool allocation base is used in which ultimate and remaining reserves receive equal weight. A further change was made in the order of allocation. In the old system economic allowances were deducted first from the provincial allowable with the remainder being allocated on the basis of reserves. In the present plan allocation first takes place on the basis of reserves followed by any adjustments necessary to insure that all pools receive their floor allowances. Allocation between wells within a pool has also changed in the new plan. Previously, the allocation for a well was found by dividing the pool allocation by the number of qualifying wells in the pool. Now a well's allowable depends on

the amount of acreage attributable to the well relative to the total acreage of the pool. The maximum area which one well may drain has also changed. Previously the limit was generally one quarter section, whereas, under the new system of production spacing units, one well may drain up to nine quarter sections.

The changes listed above represent the major differences between the old and the new plan. All of these changes were not immediately implemented by the Board at the time of the publication of its report. In the report the Board outlined varying transition periods for the gradual phasing in of the different sections of the new plan in an attempt to minimize the disallocation caused by the switch from the old to the new plan. However, by May 1st, 1969 all sections of the new plan are to be fully implemented.

CHAPTER IV

THE POSITION OF THE OIL SANDS WITHIN THE SYSTEM OF PRORATIONING

In the preceding chapters, the status of the Athabasca oil sands within the system of prorationing and their impact on the conventional industry via the system of prorationing have been ignored. In this chapter these two areas are discussed.

Recently, there has been much controversy on the subject of how much of the provincial allowable should be granted on a guaranteed and fixed (or increasing) basis to those producers with operations in the oil sands. The reason why the amount allocated to them must be guaranteed is that no producer would be willing to make the huge fixed investments necessary in order to produce the oil from the tar sands without first having a guaranteed market for his product. As a result, an allocation made to a tar sand operation represents a permanent monthly reduction in the amount of the provincial allowable that can be claimed by the producers of con-

ventional crude.[1] Herein lies the basis of the controversy surrounding any increase in production from or any further development of the oil sands.

The oil sands, located in Northern Alberta along the Athabasca River north of Fort McMurray, cover an area of approximately 13,000 square miles and contain reserves estimated to be 300 billion barrels of oil. This amount is approximately equal to all the proven conventional reserves throughout the rest of the world.[2] The oil trapped in the tar sands is produced commercially by a process pioneered by the Alberta Research Council and, at present, put into operation by Great Canadian Oil Sands at their plant at Fort McMurray. The plant, which began production in July of 1967, will be producing 45,000 barrels per day after the first few months of adjustment.

The crude produced is of the heavy hydrocarbon type. While this type of crude is not readily interchangeable with the medium and light crudes it can be

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[1] The terms "non-conventional" or "synthetic" crude are used to refer to any crude produced from the oil sands, whereas the term "conventional crude" refers to crude produced by the traditional methods.

[2] Estimates of the reserves contained in the Athabasca tar sands have ranged from 100 billion barrels to 600 billion barrels. The most popular figure quoted is 300 billion barrels. (J.P. Lounsbury, The Canadian Petroleum Industry: The Next Five Years [Toronto: Toronto Dominion Bank, 1962], p.6).

upgraded sufficiently by various processes to compete in the same markets with the medium and light conventional crudes.

The right to produce the oil from the tar sands, plus the guarantee of a market for the oil produced, was granted to Great Canadian Oil Sands by the Government of Alberta in October of 1962. At this time, Premier Manning issued a statement in which he set forth the Government's policy with regard to further development of and expansion of the markets for the crude from the tar sands. It was decided that production of synthetic crude was to be limited to a volume equal to 5 per cent of the total demand for Alberta crude if the synthetic crude was to be sold in markets that were within reach of the conventional industry. An application to produce synthetic crude that was to be sold in markets "clearly beyond present or forseeable reach of Alberta's conventional industry"[1] would be approved without the 5 per cent restriction.

The scale and timing of any subsequent developments of or increments in oil sands production were to be related to the life index of proven reserves of con-

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[1] Government of the Province of Alberta, Oil Sands Development Policy (February, 1968), p.1.

ventional crude in the Province. This stipulation was made with the intention of insuring that "market growth enables the conventional industry to produce at a greater proportion of its productive capacity".[1] At the time of Premier Manning's statement, the life index of proven reserves stood at approximately 22 years.[2] It was felt that no major new development of the tar sands should take place until this index was approaching a level of 12 to 13 years.

With the issuing of the first Oil Sands Development Policy in 1962, Great Canadian Oil Sands was given permission to construct a processing plant which was granted a production rate of 45,000 barrels per day. Originally, the maximum rate of production had been set at 31,500 barrels per day. It is not at all clear how this figure, or the later figure of 45,000 barrels per day, were computed, for nowhere is it stated which year's market demand is to be multiplied by 5 per cent to find the output level for synthetic crude. In 1963 total demand for Alberta crude was 534,100 barrels per day, 5 per cent of which is equal to 26,705 barrels per day. If the figure used for "total demand" were a pro-

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[1] Ibid.

[2] The life index of reserves is equal to the provincial remaining reserves of a given year divided by the total production of that year.

jection of what demand was expected to be in 1967 (the year that the plant was scheduled to start production) then the demand figure used was overly optimistic, for in 1967 total demand was 772,900 barrels per day. Five per cent of this figure is equal to 38,645 barrels per day, which means that the production rate granted Great Canadian Oil Sands was in excess of 5 per cent of total demand by 6,355 barrels per day.[1]

In February of 1968, Premier Manning issued a revised Oil Sands Development Policy. The new policy contains several important changes. First, the markets that may be served by synthetic crude are redefined. The markets are considered in terms of three categories, "within reach" markets, "new" markets, and "beyond reach" markets. Depending on which of these markets is to be served by the synthetic crudes, different rules apply to the rates of production and growth allowed a synthetic crude producer.

A "within reach" market is defined as one which can be supplied by conventional crude. This includes those markets which are presently supplied by conventional crude and, as a subheading, "new" markets. A "new" market is "one not being served today; one over and

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[1] The production figures are from Oilweek, February 19, 1968, p.79.

above the normal growth in existing markets; and one representing a net increase in the total market."[1] The total amount of synthetic crude that can be shipped to the combined "within reach" and "new" markets is to be 150,000 barrels per day, a limit that will tentatively remain in effect for five years.

Other restrictions may keep the actual level of synthetic crude production considerably below the maximum of 150,000 barrels per day. For example, applications proposing the marketing of synthetic crude in markets currently supplied by the conventional oil industry will be considered on the basis of the trend in the life index of conventional reserves. The decision regarding such an application will not be influenced, however, as it would have been under the previous policy, by the existing level of capacity utilization in the conventional oil industry.

With regard to applications for marketing synthetic crude in "new" markets, the Government will allot 50 per cent of the "new" market to synthetic crude with the remaining 50 per cent going to conventional crude. It was felt that this incentive for the synthetic crude producer to find new markets would mean that the con-

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[1] Oil Sands Development Policy, p.9.

ventional industry would benefit by the growth of the synthetic crude industry since "this modification of the policy would provide the conventional industry with an immediate share of markets which if otherwise obtained at all would have been obtained several years later."[1] Thus it was felt that the definition of "new" markets as described above would not adversely affect the production rates of the conventional industry.

With regard to applications to produce synthetic crude that is to be marketed in "beyond reach" markets, no restrictions on production would be made. "Beyond reach" markets are those markets "which Alberta's conventional industry is not now serving nor can reasonably be expected to serve in the foreseeable future because of price, quality specification or other reasons".[2]

The effects on the conventional industry as a whole and on the two groups within the industry (the majors and the independents) of the new oil sands policy are difficult to estimate at this time. The purpose of this section is to point out the kind of information that would be required in order to analyse these effects.

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[1] *Ibid.*

[2] *Ibid.*, p.7.

To study the impact on the conventional industry as a whole, estimates of the future costs of producing of synthetic crude versus conventional crude would have to be made. For such estimates, assumptions would have to be made about finding rates in the conventional industry, the quality and quantity of conventional reserves found, and technological advances in synthetic production processes. At present, the average finding cost per barrel of crude is $1.27.[1] A similar estimate for synthetic crude is not available and will not be available until the Fort McMurray plant will have been fully operational for at least a year.[2]

Estimates would also have to be made regarding the extent and timing of the development of the oil sands, i.e., whether production will reach the maximum of 150,000 barrels per day and, if it does, how soon it will reach it. Then, if the timing of oil sands development could be predicted, estimates of total demand for Canadian crude at the time of any increase in production from the oil sands would have to be made. Such estimates would, in turn, depend on the import policies of the United

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[1] Oilweek, February 19, 1968, p.89.

[2] This estimate was made by M. A. Carrigy, geologist with the Alberta Research Council.

States, production costs of Canadian conventional and synthetic crude vis-à-vis production costs in the rest of the world, the political stability of other major oil producing areas, particularly the Middle East, the transportation facilities available at that time, plus any technological changes that may cause the demand for petroleum products to increase or decrease.

The effect of the development of the oil sands on the two groups within the conventional industry could differ greatly. Since any new production from the oil sands requires a huge initial outlay it seems likely that the majors are the group which will be most involved with the development of the tar sands. For a company with the required amount of investment funds and access to the specialized technology required to produce synthetic crude the tar sands represent an attractive investment opportunity. There are three major advantages to producing from the oil sands. First, a producer of synthetic crude receives a fixed (or increasing) allowable each month so that the disadvantages of monthly production rates that vary with demand (as they do for conventional producers) are removed. Secondly, because the oil from the tar sands is not prorated it means that an integrated company can supply its own refinery with its own oil and thereby realize all possible profits at both the production and refining level. With prorated oil the refinery,

in effect, has to buy oil from all producers, not just from the refining company's producing operations. Thus some of the profits are paid out to other producing companies. Thirdly, synthetic crude is low risk crude in the sense that the uncertainties attached to exploring for conventional crude are removed. The one uncertainty that still exists for the synthetic producer is that the process used by a company to obtain the crude from the tar sands will cost more than the price received for the crude. Because of the guaranteed market given synthetic crude the cost need not be less than the cost of producing conventional crude in Alberta: it need only be less than the price received for Alberta crude.

Because of the three advantages listed above, further development of the tar sands will, therefore, not necessarily have a detrimental effect on the majors if it can be assumed that most of the majors will be involved, sooner or later, in synthetic crude production. At present many of the majors have already made applications to develop production outlets in the tar sands. Shell Canada Limited and Syncrude Limited (which is owned 30 per cent each by Richfield, Cities Service, and Imperial Oil and 10 per cent by British-American) have both submitted applications which are presently being considered by the Government of Alberta.[1]

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[1] Financial Post, November 27, 1967, p.1.

Because an individual independent does not have the financial backing necessary for undertaking a project in the tar sands an independent producer might share in the development of the tar sands either by pooling resources with other independent producers to start their own oil sands project or, more likely, by becoming a small, part-owner of a largely major-owned project. Another way in which the independent producers may adjust to increased production from the tar sands is by shifting the emphasis of their exploratory activity and production away from finding and producing oil to finding and developing reserves of natural gas, sulphur or other valuable minerals. However such shifts would only be necessary if it is assumed that increasing production from the tar sands causes an absolute decline in the amount of conventional crude needed to meet the market demand. If, instead, it is assumed that the total demand for both conventional and synthetic crude increases, any detrimental effects on the independents of increased synthetic crude production may be softened or even eliminated.

CHAPTER V

ANALYSIS OF THE EFFECTS OF THE NEW SYSTEM OF PRORATIONING

The period May 1, 1965 to May 1, 1969 represents the transition period during which time the old proration plan is to be gradually phased out and the new plan introduced. As a result, an accurate analysis of the overall results of the new plan is not possible. Nevertheless, it is possible at this stage to see some very definite changes that are taking place and some significant trends developing which seem to be attributable to the workings of the new prorationing system.

The most obvious of these changes is the marked reduction in lifting costs.[1] The reduction has come about

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[1] The Oil and Gas Conservation Board has estimated the direct savings to oil companies because of the wider spacing to be about $65 million during the period 1965-1967. This estimate is based on the fact that over 2,400 capable wells have been shut-in in existing pools (which represents a saving of approximately $10 million in operating costs) and on the estimate that approximately 700 wells that would have been drilled under the old plan have not been drilled (at an estimated saving of $80,000 per well). (Canadian Petroleum, July, 1967, p.12.)

because there has been a significant decrease in the number of wells that must be drilled and/or operated in order to drain a pool. Two specific changes in the proration plan have led to this reduction: (1) the minimum allowable received does not cover drilling costs, only completion and operating costs, with the result that there is no compensation or "reward" for drilling extra wells; (2) the formation of production spacing units is encouraged, accompanied by a formula which takes into account the acreage of a well and increases the allowable as that acreage increases. Under the old system there were no such incentives to drill fewer wells, i.e., the more wells the greater the allowable, with the result that many wells which were not essential for the efficient draining of a pool were drilled and lifting costs were proportionately higher. For example, in April of 1965 there were 890 capable wells on 40 acre spacing in the Redwater field. One year later, with the formation of production spacing units averaging 145 acreas, the same pool allowable was being produced by only 370 wells, a reduction of 520 wells.[1] As to the effect on new wells being drilled, the number that were drilled after the introduction of the new plan declined sharply from

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[1] Ibid.

3,571 in 1965 to 2,978 in 1966.[1]

Since the introduction of the new proration plan there has been a tremendous increase in exploration in Alberta. How much of the increase is due to the new proration plan is difficult to estimate. It is possible that part of the savings resulting from the reduction in the amount of required development drilling may have been channeled into exploration. It is also possible that the increased emphasis on reserves in the allocation formula of the new plan encouraged greater exploration activity.

A further effect of the emphasis on reserves has been the greater inducement to initiate secondary recovery projects. Expenditures for such projects increased from $7.5 million in 1964 to $9.3 million in 1965 and $9.6 million in 1966.[2] The result of the large increases in expenditures is that, in producing areas, enhanced recovery schemes now occupy 54 per cent of the area as compared with 33 per cent before 1965. In this respect, then, the new system of prorationing seems to be promoting good conservation practices.

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[1] Oilweek, February 19, 1968, p.86.

[2] Canadian Petroleum, July, 1967, p.10.

During the hearings held in 1963, various companies in the industry pointed out that the emphasis on reserves would significantly increase the allowables of high reserve per acre pools to the detriment of low reserve per acre pools. (It should be noted that the terms "low reserve per acre" and "high reserve per acre" are strictly relative terms. Whether a low reserve per acre pool is economically viable, given the demand conditions, will depend, because of prorationing in Alberta, strictly on the size of other reserves in the Province. That is to say, if such a low reserve per acre pool were allowed to produce at a rate close to its MPR, in other words, consideration is given only to good engineering practices and not to market demand, then in many cases such production would be very profitable. Because of the demand/supply conditions, however, and because of the size of the reserves of the pool relative to those found in other pools in the Province, the allowable assigned to the pool may be so small as to make production from the pool uneconomical. Therefore, a prorationing system that emphasizes the size of reserves above any other factor when allocating the provincial allowable may result in pools, which by most standards represent economically exploitable reserves, being shut-in and therefore wasted.

The companies complaining of the increase in allowables given to the high reserve fields were the independent producers. They felt that the emphasis on reserves would cause a decline in exploration and would result in the shutting-in of normally economic reserves. They felt that these adverse effects could take place for several reasons. Since the independents have the larger part of their operations in the low reserve per acre pools and since the independents are responsible for more than half of the exploration activity in the Province, any large reduction in the revenues of the independents (caused by their greatly reduced allowables) would cause a sharp reduction in exploration activity.[1] Furthermore, because the returns to low reserve per acre pools would often not justify their development, much of Alberta's oil would not be worth developing. Thus, with only very large discoveries receiving any rewards, the incentive to explore would be reduced. The effect of reducing the allowables of the low reserve pools would also cause many of them to be shut-in, even though, if given different demand/supply

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[1] In 1962, 65 per cent of the new field wildcats drilled in the Province were operated by the independents. (IPAC, Submission to the Oil and Gas Conservation Board, p.4.)

conditions, these pools would normally be considered economically exploitable. Therefore, the independents reasoned that a system with its primary emphasis on reserves would result in some waste of the Province's reserves.

So far, only some of the independents' fears appear to have been justified. Exploration has not declined. To the contrary, it has increased considerably, but how much of this increase is due to the new prorationing system is very difficult to estimate. Other events and circumstances may have been of equal or even greater importance in encouraging exploration. First of all, it was the independents (for example, Banff and Dome) who made the discoveries of the extremely high reserves per acre pools in the Keg River area (Rainbow) and at Zama with the result that the revenues of the independents did not decline as severely as expected. Secondly, the formations in which these very prolific reserves were found were formations that were not previously considered as likely to contain oil. Since the independents are well represented in areas containing these formations (often, in fact, because the majors had farmed out these tracts of land to the independents thinking them to be poor oil prospects) the independents have found themselves with land holdings of great potential. Thus there has been great

incentive for them to explore.

A third reason is that more incentive and the revenues needed to explore were provided by the substantial increase in sales caused by the Middle East crisis in June of 1967. Fourthly, finding rates in the U.S. have been declining steadily resulting in steadily rising costs per barrel of oil produced in the U.S. On the other hand, the cost of finding crude in Alberta has been falling and is now approximately one-third that of the U.S. As a result, many investors have been attracted to Alberta.[1] A fifth reason is that the search for oil has been greatly furthered, and many previously undetected high quality reef prospects have been discovered, because of the great leaps forward in seismic technology afforded by the computerization of data and reports. Thus, all of the above reasons, with or without the new prorationing system, may have been the causes of the increase in exploration.

In general, then, the effects of the new system have been beneficial in terms of increasing economic activity in the Province and in terms of promoting sound engineering practices in the production of crude. Never-

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[1] "U.S. Oil Pond About Fished Out?", Oilweek, February 19, 1968, p.51.

theless, there may be some detrimental effects of the new system. The possible premature abandonment of some pools which are considered to be still productive by most standards is perhaps the most important detrimental effect. A pool may be abandoned prematurely because the floor allowance, which was designed to cover completion and operating costs, is not large enough to cover these costs. The schedule for the floor allowances was based on the costs of completions and operations prevailing in 1964. Since 1964 both of these costs on a per well basis have risen substantially.[1] For example, the cost of financing has risen by at least 50 per cent, i.e., the average interest rate charged in 1964 was about 6 per cent while the figure for 1967 is 9 per cent or more. Because the floor allowance is too low it may not prevent the premature abandonment of normally economic wells as it was intended to do.

The greater emphasis on reserves in the proration formula has steered much of the drilling activity to Northern Alberta, where most of the recent prolific discoveries have been made. Because drilling can only be conducted in the North during the winter months,

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[1] It has been stated elsewhere that lifting costs per barrel of oil have declined considerably because of the fewer wells required to produce the same amount of oil. However, the completion and operation costs on a per well basis, which are what the floor allowance covers, have increased considerably.

the concentration of activity in this area has tended to make drilling a very seasonal occupation. Since a high degree of skill and specialization is required of the men working on drilling rigs and since the equipment needed for drilling is also highly specialized, the increased seasonality has many disadvantages in terms of resources being in short supply in the winter and lying idle in the summer. Futhermore, the drilling industry has been adversely affected by the sharp decrease in the number of wells drilled. This latter adverse effect is more of a transitional problem, however, which will tend to correct itself over time as the number of drilling companies declines and/or as the number of wells drilled increases to the previous level. The detrimental effects of the increased seasonality of the available work will not be so quickly removed.

One other aspect of the new plan, like the increased emphasis on reserves, has had both good and bad effects. The good results from the wider spacing of wells allowed by production units have already been discussed. The detrimental effects of the introduction of production units are caused more by poor administration than by a faulty concept. Originally, the criteria for deciding how many and which drilling spacing units could be joined together to form one production spacing unit

were very clear and could lead to no conflicts. For various reasons, however, in some cases the Board has decided not to use its original rules-of-thumb and, instead, has allowed production spacing units to be formed on the basis of the geological data presented by the interested companies. Since the interpretation of geological data is a very complex and very subjective task, the granting or withholding of permission to form a production spacing unit now contains a large element of arbitrariness which was not present when the prescribed rules-of-thumb were followed in all cases.

CHAPTER VI

THE EFFECTS OF PRORATIONING ON THE PRICE, OUTPUT, AND CONSERVATION OF OIL IN ALBERTA

A. The Effects of Prorationing on the Price of Alberta Crude

In this section the extent of the influence of prorationing in Alberta on the price of Alberta crude is outlined. The general structure of the world petroleum pricing system will not be dealt with here.[1] Instead, this section concentrates on the immediate determinants of the price of Alberta crude, omitting any analysis of the many complex variables which influence these primary determinants.

Very simply, the well-head price received for Alberta crude is equal to the price of crude at the refining centre to where the crude is sent (such as Sarnia, Vancouver, the Puget Sound area, etc.) less the

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[1] A very complete analysis of pricing in the petroleum industry can be found in Ralph Cassady, Jr., Price Making and Price Behavior in the Petroleum Industry, (New Haven: Yale University Press, 1954).

transportation costs (pipeline tariffs) from the well to the refining centre. The manner in which the price at the refining centre is derived is a more complex process.

In the 1930's the price of crude throughout the world was stabilized around the United States Gulf Coast prices. At this time the United States was the world's largest net exporter of oil.[1] After World War II production from the Middle East grew very rapidly and soon represented a significant proportion of total world production. At some given point in time an exported barrel of United States crude could compete with an exported barrel of Middle East crude at a point X in the Mediterranean. As Middle East production became more prolific and the price of Middle East crude declined, point X moved across the Atlantic until it came into contact with the Eastern Seaboard. When point X reached the Eastern Seaboard the United States became an importer of oil.[2]

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[1] William J. Murray, Jr., "Market Demand Proration," in Essays on Petroleum Conservation Regulation, ed. by Wallace F. Lovejoy and I. James Pikl, Jr. (Dallas, Texas: Southern Methodist University, 1960), p.74.

[2] This discussion represents an adaptation of the Levy "high and low of the range" theory which is used to explain the level of world prices. It is described in more detail by Wayne A. Leaman, The Price of Middle East Oil (New York: Cornell University Press, 1962), pp.98-103.

Immediately there was much lobbying in Washington and resistance on the part of any producers who did not have production facilities in the Middle East. Their aim was to prevent any increase in imports. The lobbying of these groups, who would be hurt by the increase in imports by having their allowables cut, was successful. In March of 1959 the Mandatory Oil Import Program, which limited total imports to 12.2 per cent of total demand, was initiated. Because of Canada's strategic position Canadian crude was exempted from any import restrictions (other than a "gentleman's agreement" between the two governments to limit the annual rate of increase of Canadian imports to about 15 per cent).

The result of the U.S. import restrictions and Canada's favored position is that there is, in effect, a North American pricing system. Since it is in this North American market that Canada competes, Canadian well-head prices plus transportation costs need only be below those of United States crude to be competitive in the markets to where Canadian crude is exported. Thus, the structure of well-head prices in Alberta is based on the level of prices prevailing in the United States. In as much as U.S. crude prices may be affected by prorationing,

then, indirectly, so are Alberta crude prices.[1] It cannot be said, however, that prorationing in Alberta causes an upward bias in prices of Alberta or Canadian crude. The above statement is made on the assumption that (1) the costs of Alberta crude plus transportation costs to the export markets in the United States are as they are now, i.e., less than the price of crude in the United States, and (2) that the potential supply is greater than current demand so that prorationing is done only to parcel out a limited demand, not to limit the supply.

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[1] Ralph Cassady, in his book Price Making and Price Behaviour in the Petroleum Industry, p.113, supports the theory that prices are at a higher level because of prorationing. Many economists share his view. Generally, however, any analyses made of the effects of prorationing on prices seem to consider only the short run. It is not at all clear what the long run effects are. If it is assumed that the only limitations on production are those set according to a pool's MPR and that there is an over-supply situation similar to the one which presently exists, it seems likely that the immediate effect of the removal of prorationing would be a sharp decline in prices. Unless the decline were checked by inter-company fixing of prices, prices would fall to levels unrelated to the costs of producing the oil and, more important, unrelated to the costs of finding oil to replace the reserves that are consumed. The result would be that many companies would have to cease operations and the investment funds needed for exploration (to replace the reserves consumed) would be redirected to other more stable and more profitable industries. Productive capacity would decline until the supply equalled demand or fell below it. In such a situation of scarce oil it is difficult to estimate what the price would be. Regardless of where the price does settle it would once again fluctuate wildly with the first sizeable increase in the supply. The timing and size of any such increase would, of course, be completely unpredictable.

Prorationing in Alberta may not affect the level of Alberta crude prices but it definitely affects their stability. The main cause of price instability is an imbalance between total supply and total demand. Since equating the amount produced with the amount demanded is the purpose and result of prorationing, the main cause of instability in prices is removed. To the extent that stable prices reduce costs, by reducing the waste caused by sharp fluctuations and by making financing less expensive, it could be argued that prorationing makes possible a lower price per barrel of crude in the long run than would the sharply fluctuating prices that would result from having no prorationing.

B. The Effect of Prorationing on the Level of Production in Alberta

In order to analyse the effect prorationing has on the level of crude production in Alberta it is necessary to analyse the effects of prorationing on Canadian imports of crude, Canadian exports of crude, and production levels in the other provinces.

There are many political and economic variables (too complex to be dealt with here) which, in conjunction with prorationing, influence the level of imports. As a result, the analysis here will be a simplified one

and will concentrate on the most obvious effect that prorationing has on imports.

Most of the large refiners in eastern Canada, where imported crude can compete with Canadian crude, have large production facilities in other parts of the world, such as the Middle East. If they import and use their own foreign crude in their refineries they gain because the crude they produce in the other regions is not prorated. This means that any increase in the demand for their foreign oil from their Canadian refineries accrues directly to their own company and does not have to be shared amongst all producers. In other words, no profits, at the production level, have to be shared amongst other producing companies by allowing them to supply part of the refinery's needs, as would be the case if a refinery had to take prorated oil. Thus, there is a very real incentive to the companies with international operations to increase the use of their unprorated foreign oil in Canada rather than use their prorated Canadian oil. Therefore, in this area, prorationing may have the effect of increasing imports.

Walter Levy, in his report The Outlook for Canadian Crude Production and Markets, has suggested another effect that the prorationing scheme may have on

the level of imports.[1] He has proposed that, because of the emphasis on reserves in the new proration plan, "the very substantial Rainbow discoveries could well result in a significant shift in Alberta allowables from established to incoming producing areas, with significant effects on the relative producing position of various companies and hence their incentives or disincentives to draw crude from Alberta."[2] In other words, if a refinery of an integrated company decides to increase its output and, because of the shift in allowables the company's share of any increase in demand for Alberta crude has declined, the incentive for such a refinery to meet its increased demand by importing the company's unprorated oil will have increased. Thus, for both of the reasons given above it seems likely that prorationing has made imported crude more desireable for refineries of integrated companies than it would have been otherwise.

Prorationing could influence the level of exports of Canadian crude in three ways. On the one hand, prorationing may cause exports to be higher than they would be otherwise because of its part in making Canadian

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[1] Levy, The Outlook for Canadian Crude, p.II-19.

[2] Ibid.

crude a secure and stable supply, and therefore a desirable source to fill the requirements of U.S. refiners. On the other hand, prorationing may work to decrease Canadian exports. First, it reduces the need for the individual producer to search for new markets since, with prorationing, each producer is guaranteed a share of the market and therefore does not need to actively search for new markets for any new reserves he finds. Secondly, it reduces the incentive of an individual producer or even a groups of producers to establish new markets, even by reductions in prices, since any additional volume captured will have to be prorated amongst all producers.

A third reason why prorationing may have an adverse effect on the level of exports is the preference of the refineries of the integrated companies in the U.S. (as in Canada) to use crude that is unprorated as much as possible. That this preference is a significant factor influencing the level of Canadian exports is illustrated by the changes taking place in the Puget Sound area. Oilweek has predicted that in spite of the 20 per cent increase in Canadian exports into the Chicago area, total Canadian exports to the U.S. may decline.[1]

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[1] Oilweek has estimated that the decrease will be in the order of 14,000 barrels per day, (Oilweek, February 19, 1968, p.78).

This decline will mostly be caused by the influx of Alaskan crude into the PugetSound area where it will replace the Canadian oil presently serving these markets. Prorationing most likely had some effect on the decrease in the use of Canadian crude in this area since Alaskan crude is not prorated and the refiners naturally have a "commercial preference" for the oil that their own companies are producing in Alaska. Shell, Mobil, and Texaco are the major refiners in the Puget Sound area and all three companies have production in Alaska.[1]

To estimate the influence of prorationing on production levels in the other provinces and thus on the level of production in Alberta many other factors influencing the level of production in the other provinces must be taken into account. In the other oil producing areas of Canada there is no limiting of production to market demand. The only limitations on production are those which insure good engineering practices. The other producing areas are Saskatchewan, British Columbia, Manitoba, Eastern Canada (New Brunswick, Nova Scotia and Ontario), and the North West Territories, listed in order of the size of their yearly production. Of these other areas, only the production of Saskatchewan and British Columbia are of any

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[1] Ibid., p.76.

significance in terms of total Canadian production. In 1967, Saskatchewan produced 256,200 barrels per day and British Columbia produced 59,000 barrels per day. These figures represent only 23 per cent and 5 per cent, respectively, of total Canadian production. Alberta, by comparison, produced 70 per cent of the total.[1]

As a result of Alberta's dominant position, Alberta is the "national balance wheel" (as is Texas in the United States). This means that any discrepancies in demand for and supply of Canadian crude must be balanced in Alberta by means of prorationing. The balancing function for Alberta came about for two reasons: (1) Alberta's supply far exceeds the demand for its oil while, because of Saskatchewan's and British Columbia's more favourable geographical position and their smaller reserves, and because of the fact that Alberta does not permit production at capacity, demand exceeds supply in these provinces, and (2) Alberta has the most to lose, in terms of investment, government revenues, etc. by not prorating its oil.

Because the oil of the other provinces is not prorated, as is Alberta's, any oil discovered in British Columbia and Saskatchewan is preferred over a comparable

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[1] *Ibid.*, p.79.

discovery made in Alberta. This is because the producer is allowed to produce at the level of the pool's MPR rather than having the rate of production restricted to a much lower level. Another attraction to producing in Saskatchewan and British Columbia is their greater proximity to the markets where most Canadian crude is consumed. Their more favourable geographic location means lower transportation costs.

Some of the advantage derived from the lower transportation costs is, however, outweighed by the poorer success ratios of B.C. and Saskatchewan as compared to Alberta, i.e., 60 per cent of all holes drilled in Alberta in 1967 were successful compared to 51 per cent for Saskatchewan and only 49 per cent for B.C.[1] These lower success ratios may have the effect of reducing the attraction of unprorated oil.

Thus, in order to weigh the full effect of prorationing on the level of production in the other provinces, it would be necessary to separate and weight the effects of the greater proximity to the markets of the other provinces, the differences in the success ratios, plus any further differences in costs of drilling and

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[1] Oilweek, February 19, 1969, p.87.

production due to differences in climactic, geological or geographical conditions. For example, the effect of differences in the number of barrels of oil found per foot drilled (and differences in the average cost of drilling per foot) would have to be accounted for before the net effect of prorationing could be estimated.

It can be said, however, that if all Canadian production were prorated on the basis of reserves to meet total Canadian demand, production levels in the other provinces would be far lower than they are at present, and Alberta's would be somewhat higher. That this would be so can be seen by comparing Alberta's total remaining recoverable reserves of 7,049 million barrels to Saskatchewan's 763 million barrels and British Columbia's 315 million barrels.

In summary, then, before any quantitative statements can be made as to the effect of prorationing on Alberta's total output three areas would have to be carefully examined. These areas would be the effect of prorationing on imports, on exports, and on production levels in the other provinces. In each of these areas many other variables are acting to increase or lessen the effects of prorationing. Hence, this section has been concerned mainly with pointing out some of these other variables, assessing the direction of their

influence on production levels, and assessing their influence on the net effect that prorationing has on production levels.

C. The Effect of Prorationing on Conservation

Before any discussion is possible of this area, the term conservation must be defined. In this paper, the effects of prorationing on conservation are discussed in terms of only two meanings of the word conservation, the non-wasteful physical use of a resource, and the most beneficial time horizon of that use (in the sense that returns from the resource are maximized over time).

There is little doubt that Alberta's prorationing system helps to minimize physical waste. In Section 2 of the Oil and Gas Conservation Act the term waste, "in addition to its ordinary meaning, means 'waste' as that term is understood in the oil and gas industry and includes the underground or surface loss through wasteful operations of oil or gas or of potentially recoverable oil or gas."[1] The definition of what constitute "wasteful operations" extends over three pages.

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[1] Oil and Gas Conservation Board, Report and Decision, p.13.

In summary, however, a "wasteful operation" means "the locating, completing, operating or producing of a well in a manner that results or tends to result in reducing the quantity of oil or gas ultimately recoverable from a pool under sound engineering and economic principles."[1]

Thus, the prorationing system attempts to minimize physical waste in the sense of maximizing the amount of oil recovered from a pool. The two ways in which the prorationing system does this are by reducing below-ground waste (by enforcing and rewarding good engineering practices) and by removing above-ground waste (by equating supply with demand). Thus, there is little doubt as to the direction of the effect of prorationing on conservation in the sense of the non-wasteful use of a resource.

It is much harder to analyse the influence of prorationing on the time horizon of the use of Alberta's oil reserves. In other words, is prorationing influencing the timing of the use (or production) of crude so as to maximize the net revenues over time from the resource? In two ways prorationing has the effect of preserving a larger amount of oil for future use than would be preserved without prorationing, given a situ-

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[1] _Ibid_., p.14.

ation where there is oversupply, where not all producers have direct access to transportation and marketing facilities, and where multiple ownership of pools exists. First, by setting maximum permissible rates of production (rates which are estimated to lead to the maximum recovery of oil from a pool) prorationing insures that there will be more oil both for present and future use than if uncontrolled production were allowed. Secondly, by equating monthly production with monthly demand prorationing in Alberta results in production rates that are, in most cases, well below even the MPR's of pools. Thus in both these ways prorationing has the effect of "preserving" more oil for future use.

As to whether this saving of the oil will result in greater net returns being earned by the resource depends on many different factors. If it is assumed that Alberta decides to "preserve" its oil for future use the effect on total net revenues would depend on such variables as (a) the number of substitutes found for oil, (b) the number of new uses found for oil, especially the number of these new uses that earn oil a greater return than existing uses, and (c) the finding rates and reserves throughout the rest of the world. Prorationing has little effect on these other variables except perhaps via its difficult-to-determine effect on prices.

Yet, for better or worse, prorationing does alter production rates in such a way as to allow greater use of oil in the future than there would have been without prorationing. It could be argued that, without prorationing or some other form of regulation, oil prices would fluctuate wildly, given the existing system of land holding, the existence of both integrated and non-integrated companies, and a condition of oversupply. If the range of these fluctuations, especially in the short run, were below the present level of prices, or if the average price over time were considerably below the level of prices existing under prorationing, then there might be an increase in the consumption of crude for what may be considered "low priority uses",[1] and net returns over time would not be maximized. However, the difficulty of estimating what the average price of crude would be in the long run with no prorationing makes a more rigorous analysis impossible.

It is interesting to note that nowhere in the Report on Proration of Oil to Market Demand did the Oil and Gas Conservation Board consider the effect of pro-

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[1] Edward S. Mason, "The Political Economy of Resource Use," Perspectives on Conservation ed. by Henry Jarrett (Baltimore: John Hopkins Press, 1961), p.182.

rationing on the time horizon of the use of oil, and thus its effect on the net returns oil would provide for the Alberta economy. Perhaps this was because of the fact that in order to satisfy the requirements of conservation, in the sense of maximizing physical recovery, both the rules designed to promote good engineering practices and those that equate demand and supply are needed.

CHAPTER VII

ALTERNATIVES TO PRORATIONING

A. The Concession Arrangements of the Middle East Producing Countries

In the Middle East there is no prorationing. Instead, the governments of the oil producing countries make individual concession agreements with foreign oil companies. A concession gives the foreign company the exclusive right to exploit the petroleum resources of a given area for a specified period of time. Usually the areas granted in a concesssion are very large, in some cases embracing the whole country or a major region which "either because of its geological formation or because of its political character, constitutes a well-defined territorial entity."[1] Usually the concession is granted for a very long period of time, often up to 60 years with a provision allowing the com-

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[1] George Lenczowski, Oil and State in the Middle East (Ithaca, New York: Cornell University Press, 1960), p.64.

pany to apply for extensions after that date.[1] In return for the concession, the foreign company agrees to pay the host country royalties on the oil that is produced, or give the host country a set percentage of the profits that are made from the production of the oil from the concession area.

Because of the huge area of the concessions the problems of multiple ownership of a pool do not arise, except on rare occasions when a pool straddles the line dividing two concessions. Thus the whole issue of correlative rights does not arise. Likewise, because it is to the advantage of the company to follow best possible engineering practices (unlike under a system of multiple ownership of pools) there is no need for the government to introduce rules to prevent physical waste. It is only when pools straddle property lines between concessions that wasteful methods of production are likely to occur.

Although there may be good conservation practices followed in the sense of no physical waste there is, as with prorationing, no consideration given to conservation in the sense of the best time horizon for the production of the oil of a particular country. For various reasons, such as transportation being available

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[1] *Ibid.*

in one area and not in another, or greater political instability in one area than another, a producing company may decide not to produce the oil or greatly decrease production from a concession in one country in favor of greater production from one of its concessions in another country. Since many of the governments of the producing countries in the Middle East are entirely dependent on the revenues derived from oil royalties, such a policy of "non-expansion of production"[1] can be very harmful to the orderly growth of the country's economy.

In order to combat this problem, some countries, such as Iraq, have insisted on safeguards against decreasing production being included in the concession agreements. But an attempt on a much larger scale to stabilize the revenues of producing countries, by removing fluctuations in both prices and production levels, was made when the Organization of Petroleum Exporting Countries (OPEC) was formed in 1960.[2] One of the main objectives of OPEC was to "formulate a

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[1] *Ibid.*, p.74.

[2] The following countries are members of OPEC: Venezuela, Iran, Iraq, Kuwait, Saudi Arabia, Qatar, Indonesia, and Libya.

system to ensure the stabilization of prices by, among other means, the regulation of production with due regard to the . . . necessity of securing a steady income to the producing countries . . . ."[1] In other words, the OPEC countries desired to set up a system of "international prorationing".[2] Thus, even though a concession system may eliminate the need for prorationing within a country, when the conditions necessitating prorationing in some regions are projected into the international setting, those countries not presently prorating their oil are in favor of an inter-country prorationing system.

This desire for international prorationing occurs when world supply greatly exceeds world demand, with the result that the position of a producing country, whose government depends on oil production for most of its revenues, is in a very similar position to that of a single producer in a pool where there is multiple ownership.

Whether a system of concession arrangements being made with a few huge foreign companies is in-

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[1] OPEC, Resolutions of the First Conference, September 10-14, 1960, Resolution I, 1, cited by Walter J. Levy and Milton Lipton, "The Organization of Petroleum Exporting Countries (OPEC) and World Oil," in *Exploration and Economics of the Petroleum Industy*, Vol.IV (Houston, Texas: Gulf Publishing Company, 1966), p.363.

[2] *Ibid*., p.371.

herently a better system than prorationing, in terms of which benefits the economy of the region the most, is not clear. Which system encourages the most exploration and therefore engenders the greatest amount of economic activity also is not clear. One indication as to which system may be preferable is the fact that both Libya and Egypt, relative newcomers to the oil producing fraternity, have encouraged "multiple operations rather than exploitation of a large area by a single company"[1]. These countries feel that greater activity is encouraged by the more immediate competition provided by having more than one or two companies operating in an area. However, given the system of landholding established in Alberta, given the fact that supply greatly exceeds current demand, and given the existence of both integrated and non-integrated companies operating side by side, a system based on concessions would not be operable in Alberta.

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[1] For example, Libya has granted concessions to 13 companies and Egypt has granted concessions to 7 companies. In many of the other producing countries there are only two or three operating. (Lenczowski, Oil and State in the Middle East, pp.21-23.)

B. Unitization

Unitization has often been suggested by well-intentioned economists as the solution to all the problems caused by prorationing, such as "the raising of prices through control of output",[1] and the removal of the oil industry from the competitive forces of the market. By unitization is meant the operation of a pool as a unit under the combined management of all the owners of wells or land in the pool. The pool is the most natural and most efficient unit for production. All the problems of lease-line drainage, uneven production rates, and the building-in of unnecessary capacity are removed. The operation of secondary recovery projects is greatly simplified and it is especially in this area that unitization has such tremendous advantages.

Rostow has always been one of the strongest proponents of unitization as a means of assuring "a high standard of operations from the geological point of view".[2] He feels that in order to remove all the detrimental forms of production control caused by pro-

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[1] Edward S. Mason, "The Political Economy of Resource Use," p.175.

[2] Eugene V. Rostow, A National Policy for the Oil Industry (New Haven: Yale University Press, 1948), chapters 13 and 14.

rationing, compulsory unitization should be coupled with a reorganization of the petroleum industry. The reorganization would be done so as to insure that not only is production separated from all other phases of the industry, especially transportation, but also that at no phase does any one or group of buyers or sellers dominate. Edward Mason also feels that unitization would cure some of the evils of the present system. He suggests that compulsory unitization would result in the competitive pricing of oil, "with prices equal to the marginal costs of unified pool operations."[1]

In their discussion of the positive effects of unitization, both Rostow and Mason, and many other economists, have failed to realize that even though the production of a pool as a unit decreases both costs and physical waste, many of the problems that prorationing removes are not taken care of by simply unitizing (even given that Rostow's reorganization of the petroleum industry were to take place). For example, unitizing does not alter the fact that supply greatly exceeds current demand with the accompanying result that producers in one unit are in competition with producers in other units for

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[1] Edward S. Mason, "The Political Economy of Resource Use," p.182.

limited transportation facilities and markets. Nor does unitization remove the disrupting effects caused by the fact that additions to supply are completely unpredictable both as to size and timing.

For example, if Mason's point of view is taken, it can be assumed that the producers in a number of unitized pools will set their prices according to their marginal costs of (unitized) operation at any given time t. If it is then assumed that there is a discovery made in time t+1 of a pool with prolific, high quality reserves, then the moment that production from this new discovery begins some of the pools which are already producing and whose reserves are neither as extensive nor of such good quality as those of the new pool, immediately become sub-marginal pools. If the producers in these pools then maintain the price of their oil at a level equal to their marginal costs of unitized operation there will be no market for their oil and the wells in these pools will have to be abandoned. (It is possible that for a short time the producers in these pools would be willing to operate at a loss, but if the reserves of the new pool are extensive enough and the marginal cost of operation in the new pool so much lower than in the old pools it is unlikely that the producers in these pools will be willing to sell at a loss for any length of time.

Their resources would be more profitably invested searching for better pools.) If it is then assumed that there are no new prolific discoveries made for some time and that the reserves of the "new" pool are gradually depleted with the result that the marginal costs of operation is the "new" pool begin to increase, a point in time may be reached when the sub-marginal pools of time t+1 become, once more, economically viable reserves of oil. The premature abandonment of the wells in these pools, however, means that their reserves are not recoverable with the result that this presently economic oil has been lost.

If the conditions postulated above were to exist (i.e., compulsory unitization, no prorationing, and pricing based on the marginal cost of unitized operations), the greatly varying production rates of the pools accompanied by wide fluctuations in prices would increase the hazards attached to investment in the oil industry and would tend to hamper the orderly growth of the industry.

CHAPTER VIII

CONCLUSION

It appears that the system which would most benefit the oil industry and the region where its activity takes place would be a system which combines the unitization of pools with prorationing between pools. This conclusion is based on the assumptions that the condition of oversupply will exist for some time and that both the integrated and non-integrated companies continue to produce oil in Alberta.

Before an analysis is given how first the oil industry and then the region benefit from the combination of unitization and prorationing, it is of interest to see how closely Alberta's system of prorationing approaches this "ideal". As has already been described, Alberta does prorate between pools. Unitization of pools, especially for secondary recovery projects is becoming more frequent. Since unitization of a pool can be impeded by the refusal of a few companies in a pool to co-operate, an amendment to the Oil and Gas Conservation Act made in 1957 helped to remove some of the barriers to unitization. The amendment pro-

vided for compulsory unitization of a pool if producers representing more than 50 per cent of the interests in terms of acreage in the pool requested it of the Oil and Gas Conservation Board.[1] With this amendment a possible major obstacle to unitization has been removed.

Unitization has been further encouraged by the introduction of production spacing units in the new proration plan. The production spacing units allow producers to form unit operations encompassing either part of a pool or the entire pool. Such units are similar in many respects to unitized pools and have many of the advantages of unitization even though they may only encompass part of a pool. Thus, it can be seen that Alberta's system of prorationing closely approaches the "ideal" system described at the beginning of this chapter.

The benefits the industry would derive from such a system can be divided into two areas, those derived from unitization and those derived from prorationing. Unitization, by allowing the pool to be produced as a unit, removes all need for the companies operating in a pool to drill any wells that are not essential for the

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[1] Hanson, Dynamic Decade, p.208.

efficient draining of the pool. Thus, the companies benefit from unitization by having their costs of production reduced. Unitization also benefits the industry by facilitating the implementation of secondary recovery projects. This is because any water or gas injection project requires the co-operation of all the producers in a pool. If a pool is already unitized it is to the advantage of all members of the unit to co-operate and thereby increase the total amount of oil recovered from the pool. If the pool were not unitized no producer would be willing to bear the cost of the enhanced recovery scheme and have all the producers benefit from his investment.

Before discussing the benefits of prorationing to the industry it is necessary to state the assumptions on which this analysis is based. They are that the supply of crude exceeds the current demand, that there are both integrated and non-integrated companies operating in the region, and that the timing and size of additions to reserves cannot be predicted. It is further assumed that most pools are unitized and that, therefore, most of the problems created specifically by the multiple ownership of pools are removed. Given these assumptions prorationing benefits the oil industry in two ways. First, it stabilizes the price received for

crude produced and thus makes the return on investment in the oil industry somewhat more predictable. Secondly, prorationing between pools insures that any successful exploration will be rewarded by guaranteeing all reserves a part of the market demand. This second effect of prorationing also tends to remove some of the risk attached to investing in the oil industry. Thus, by removing some of the risk, prorationing encourages continuing and steady investment in the industry and thereby encourages the orderly growth of the industry.

The benefits to the region of the proposed system can also be divided into the benefits derived from unitization and the benefits derived from prorationing. Here, too, the analysis is based on the three assumptions that are listed above.

Unitization decreases the need for the governmental body to enforce good engineering practices amongst the producers in each pool. With unitization, it is to the advantage of each producer in a unitized pool to follow good engineering practices and thus to maximize the recovery of oil from the pool. Thus the government of the region is guaranteed that its valuable resource will not be wasted, in the physical sense.

In many of the ways that prorationing benefits the industry so also does it benefit the region. Prorationing tends to create more stable conditions for large amounts of investment both by stabilizing the price of oil and by guaranteeing that new discoveries of reserves will receive a share of the market. Such investment may be both in the oil industry directly or in related but dependent industries that either supply the oil industry or require the products of the oil industry for their own operations. The growth of such dependent industries, plus the growth of the oil industry, help to speed the growth of the region.

The above analysis paints a very one-sided picture of the effects of unitization combined with prorationing on the industry and the region. Elsewhere in this paper other less favourable effects of prorationing have been described. These are that prorationing may cause the exports of a region's crude to be lower than otherwise, the imports to be higher and thus production levels lower than they would be if production were not limited to market demand. However, it is not at all clear whether in the absence of prorationing there might not be other factors that would cause production levels to be equal to or below what they are with prorationing. For example, the fact that without prorationing prices

and production levels could vary greatly might result in a significant decrease in investment in the oil industry. Furthermore, without prorationing there would be no quarantee that producers would attempt to maximize the amount of oil they recovered from each pool. With little exploration being done to find new reserves and with the old reserves being rapidly depleted it is possible that, without prorationing, production levels would be lower than they are with prorationing, even given the negative effects prorationing has on exports and imports.

In conclusion, four possible alternatives to the system proposed in this chapter have been suggested. They are (1) no prorationing, (2) compulsory unitization of pools and no prorationing, (3) unitization combined with a reorganization of the petroleum industry, and (4) a system of concession agreements. Given these alternatives and given the existing conditions (i.e., supply exceeds current demand, there are both integrated and non-integrated producers operating in the same region, the timing and size of additions to reserves cannot be predicted, and there is multiple-ownership of pools), then the system which would seem to minimize the disadvantages and maximize the benefits more than any alternative system is a system of unitization of pools combined with prorationing between pools.

APPENDIX I

[1]Glossary of Terms as Used in the Petroleum Industry

Minimum allowance - A basic allowance or a floor allowance. That part of a well's allowable which does not vary from month to month and which the well shall receive unaffected by variations in market demand as long as the aggregate of such minimum allowances does not exceed the provincial allowable.

Basic allowance - The minimum allowance of a well in a system whereby the aggregate of all minimum allowances is subtracted from the provincial allowable and the balance of the market demand is allocated and distributed according to other factors.

Floor allowance - The minimum allowance of a well in a system whereby all of the provincial allowable is allocated and distributed according to proration factors, subject to adjustment so that every qualified well may receive its minimum allowance.

Economic allowance - The basic allowance used in the previous plan more or less reflecting the cost of operating a well, the cost of completing a well, the cost of drilling a well or a combination of them. The previous plan provided for an "initial economic allowance" reflecting approximately all of the above costs to apply during the first seven years more or less of a pool's production and after that an "operating economic allowance" reflecting approximately the cost of completing a well and the cost of operating it.

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[1] This glossary is adapted from the glossary provided by the Oil and Gas Conservation Board in its Report and Decision, pp.9-10.

Remaining reserves - The total reserves, recoverable by methods employed in the pool, remaining in the pool from time to time.

Provincial remaining reserves - The total of the remaining reserves of all oil pools subject to proration in the Province.

Ultimate reserves - The remaining reserves of a pool plus the volume of oil that has been produced from the pool.

Provincial ultimate reserves - The total of the ultimate reserves of all oil pools subject to proration in the Province.

Life index - The ratio of provincial remaining reserves to the corresponding annual producing rate.

Pool allocation base - The determinant of the variable portion of the provincial allowable allocated to a pool.

Allocation factor - The ratio of the provincial allowable to the sum of the allocation bases of all the pools in the Province.

MER or Maximum Efficient Rate - The maximum rate at which oil can be produced without avoidable underground waste.

MPR or Maximum Permissible Rate - The Board's estimate of the MER of the average well in a pool.

Pool MPR - The Board's estimate of the pool MER.

APPENDIX II

[1]The MPR Formula for Oil Wells Used Prior to 1964

General Formula for the Calculation of MPR's

$$MPR = T\ F_D\ F_A\ F_{PS}\ F_{RL}$$

T = Thickness of pay

F_D = Development factor

F_A = Acreage factor = 1/40

F_{PS} = Porosity shrinkage factor = $\dfrac{\emptyset\ (1-S_{wi})\ 1/B_{oi}}{0.10\ (0.75)\ (0.75)}$

Where $\emptyset$ = average pool porosity, fraction

S_{wi} = average pool connate water, fraction

$1/B_{oi}$ = average pool shrinkage fraction

0.10 = reference well porosity, fraction

0.75 = 1 - reference well connate water, fraction

0.75 = reference well shrinkage, fraction

F_{RL} = Recovery life factor = $\dfrac{10R}{0.20L}$

10 = reference well uniform rate life well

years L = expected uniform rate life

fraction R = expected recovery

0.20 = reference well recovery fraction

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[1] Source: Charles S. Lee, "Allowables and Allowances," p.26.

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